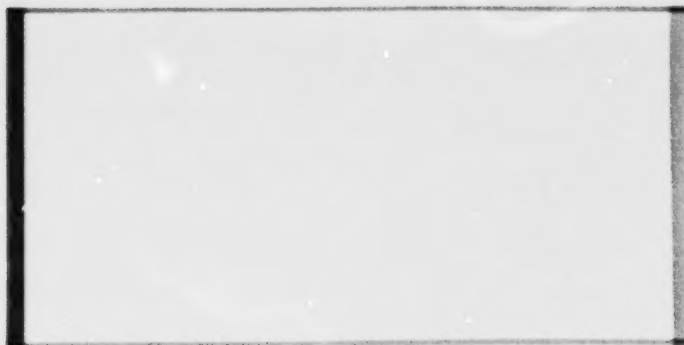


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U.S. UTILITY ATTITUDES AND EXPERIENCES
WITH THE
PUBLIC UTILITY REGULATORY POLICIES ACT
(PURPA)
AND ITS POTENTIAL
RELEVANCE IN CANADA

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Foreword

This report was prepared for the Renewable Energy Division, Department of Energy, Mines and Resources for discussion purposes. The views and opinions expressed in this publication do not necessarily reflect those of the Government of Canada or any department thereof.

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EXECUTIVE SUMMARY

The U.S. Public Utility Regulatory Policies Act (PURPA) is a regulatory instrument that imposes the expected economic results of a simulated free market in generation, on electric utilities. Congress did not challenge the utilities' monopoly in the distribution of electricity, but felt that competition in the generation of electricity would best ensure the development of the least cost electrical generation options.

Under PURPA, utilities are required to purchase electricity from small power producers (SPPs) at a rate geared to the utility's actual benefit from the purchase, that is, the utility's full "avoided cost". In brief, avoided costs are based on the price of a utility's newest and most expensive central generation facilities. To the extent that SPPs can generate electricity at a lower cost than the utility's most expensive sources, it can require the utility to purchase its power at the utility's avoided cost.

Generally, U.S. utilities are now beginning to accept their new partnership in electrical generation. In 1982, U.S. utilities purchased 3,508 MW from SPPs. By 1992 the figure is estimated to reach 12,547 MW, and by 2000 approximately 30,150 MW. As a result of the increasing reliance on third party developed small generation facilities, conservation and load management programs, U.S. utilities will be cutting their construction requirements by at least \$45 billion over the next decade.

The most important long-term benefit of PURPA was the establishment of an accurate pricing mechanism for the consideration of electrical generation options. Such consideration prevents overall energy market distortions. Avoided cost rates reflect the actual benefit to a utility of purchasing electricity from private sources.

While Canadian utilities will permit SPPs to interconnect, buyback rates are not based on avoided costs anywhere in Canada. It is the primary conclusion of this report that governments and regulatory agencies at all levels should act to encourage and initiate discussion between SPPs and Canadian utilities concerning the establishment of means to publicly determine true avoided costs and thereby, the development of privately generated electricity in Canada.

RÉSUMÉ À L'INTENTION DE LA DIRECTION

Aux États-Unis, la Public Utility Regulatory Policies Act (PURPA) (Loi sur les politiques de réglementation des services publics) impose aux services publics d'électricité les résultats économiques attendus si l'on simulait un marché libre de production. Le Congrès n'a pas contesté le monopole des services publics sur la distribution de l'électricité, mais il croit que la concurrence au niveau de la production de l'électricité est le meilleur moyen d'assurer l'élaboration des options les moins coûteuses pour la production de l'électricité.

En vertu de la PURPA, les services publics doivent acheter l'électricité de petits producteurs, à un taux calculé en fonction du profit réel du service public sur cet achat, c'est-à-dire le «coût évité» total pour le service public. En résumé, les coûts évités sont fondés sur le prix des centrales électriques du service public les plus récentes et les plus chères. Lorsque les petits producteurs d'électricité peuvent produire de l'électricité à un coût inférieur à celui des sources d'approvisionnement qui coûtent le plus cher au service public, cette loi peut obliger ce dernier à acheter son électricité au coût évité.

En général, les services publics américains commencent maintenant à accepter leur nouveau rôle d'associés dans la production d'électricité. En 1982, les services publics américains ont acheté 3 508 MW des petits producteurs d'électricité. D'ici à 1992, ce chiffre devrait atteindre 12 547 MW et d'ici à l'an 2000, environ 30 150 MW.

En se fiant davantage à de petites centrales électriques exploitées par des tiers et grâce à leurs programmes d'économies d'énergie et de gestion de la puissance appelée par un réseau, les services publics américains réduiront leurs besoins en construction d'au moins 45 milliards de dollars au cours des dix prochaines années.

Le principal avantage de la PURPA, à long terme, est l'établissement d'un mécanisme de tarification précis pour étudier les choix en matière de production d'électricité. Cette étude évite les distorsions du marché de l'énergie en général. Les tarifs au coût évité reflètent l'avantage réel pour un service public d'acheter l'électricité de sources privées.

Bien que les services publics canadiens permettent l'interconnexion des petits producteurs d'électricité, les tarifs de rachat ne sont nulle part au Canada fondés sur les coûts évités. Les auteurs de ce rapport concluent essentiellement que les gouvernements et les organismes de réglementation à tous les niveaux devraient faire en sorte d'encourager et de mettre en branle des discussions entre les petits producteurs d'électricité et les services publics canadiens relativement à l'établissement de moyens de fixer publiquement les coûts réels et par conséquent, d'encourager la mise sur pied de centrales électriques privées au Canada.

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INTRODUCTION



A.1 INTRODUCTION

As part of the overall U.S. energy strategy for the 1980's, the U.S. Congress legislated a return to competition in electrical generation in 1978.

The legislative package included a broad range of initiatives.

The National Energy Conservation Policy Act of 1978 (NEA) was sent to Congress by President Carter on April 29, 1977 and the House of Representatives passed it without major changes in August of that year, forwarding it to the Senate for approval. The NEA was to reduce the growth in energy demand; cut the importation of petroleum; extend supplies of natural gas; encourage the use of coal and renewable energy resources, principally various solar technologies; and promote energy conservation and more efficient use of utility generation facilities.

After passing through the House of Representatives with few changes, the Senate divided the act into five separate bills:

- * The Energy Tax Act which established credits and capital cost allowances for a range of energy products.
- * The National Energy Conservation Policy Act.
- * The Powerplant and Industrial Fuel Use Act.
- * The Natural Gas Policy Act.
- * The Public Utility Regulatory Policies Act, (PURPA).

Rewritten, the bills passed the Senate, and each was presented to a joint conference committee of the House and Senate. The conference committees were lobbied intensively by industry, utilities, environmental, and other interest groups, as well as by the Carter Administration. Each of the bills became law in 1978.

This study will examine PURPA, the Public Utility Regulatory Policies Act. Specifically, we wish to:

- 1) Report on the introduction and ongoing implementation of an act which had the intention of promoting the development of privately financed small power generation.
- 2) Document the experience of U.S. utilities with Small Power Producers (SPP's) investigating the determination of avoided costs, capital considerations, contract arrangements, non-performance issues, insurance, the effect on utility power generation planning, grid management, the number of small generation facilities, the number of developers, geographical distribution of qualifying facilities, the type of energy supply used, and total power production.
- 3) Document the experience of U.S. SPP's in the determination of avoided cost, contract arrangements, non-performance issues, and the industry's expectations of continued market development both with and without the extension of applicable federal and state tax credits.
- 4) Document the attitude of U.S. financial institutions actively raising and providing capital for large utility and small power production projects to compare their attitudes regarding large and small projects, and investigate whether financial difficulties encountered by U.S. utilities could affect investor attitudes toward Canadian utilities' projects and capital requirements.
- 5) Discuss the extent to which U.S. experience in this area is relevant to what aspects of the Canadian context in terms of feasibility, and advantages and disadvantages of similar arrangements as part of Provincial power production policy.
- 6) Document the extent to which Canadian utilities have established power purchase policies, discuss the suitability of existing arrangements from both the utility and small power producer perspectives and indicate possible areas for further development or improvement in Canadian utility policy.
- 7) Characterize the potential opportunities for small power generation in Canada and discuss the extent to which developments in power purchase policies could increase the demand for small power generation projects.

CHAPTER ONE

PUBLIC UTILITY
REGULATORY POLICIES
ACT
of 1978
and
INDEPENDENT ELECTRICAL
GENERATION

CHAPTER SUMMARY

- 1) Cost escalation, long project lead times, and slackening demand have combined to put a serious strain on electric utilities in both the United States and Canada. To address these concerns the U.S. Congress legislated a return to competition in electrical generation in 1978.
- 2) Growth in demand was declining from a 7% annual rate experienced in the 1960's, to an average increase of 3% annually from 1973 to 1978. This drop in demand left utilities with unplanned excess capacity. In fact, the national average reserve capacity had doubled from the 20% normally maintained.
- 3) In rate hearings throughout the United States, utilities requested substantial increases to address their poor cash flow situation. With mounting evidence that the U.S. utility sector was being financially squeezed by a continuing concentration on central generation facilities, many new companies began independent negotiations to build small power production facilities. The utility sector resisted these attempts, leading the "new" energy industry to call for a legislative solution.
- 4) The utility lobby indicated in no uncertain terms that a new regulatory scheme to promote the development of private electrical generation was both unnecessary and harmful to their interests.
- 5) Control of distribution made the utilities impervious to allowing any form of competition in the production of electricity. They were able to control negotiation for the purchase of electricity from private sources by entering only into contracts that had significant benefit to the utility.
- 6) Even for those utilities that saw long term potential in small power production, the institutional barriers made a receptive response impossible.
- 7) PURPA is a regulatory instrument that imposes the expected economic results of a simulated free market for power generation on utilities. Congress did not challenge the utilities monopoly in the distribution of electricity, but felt that competition in the generation of electricity would best ensure the development of the least cost electrical generation options. A base of regulation was necessary to allow the economics to work and to encourage arms-length bargaining between SPPs and utilities. PURPA created a clear distinction between the utilities production and distribution functions.

- 8) To qualify as a SPP the total capacity of any facility cannot exceed 80 MW, no more than 50% of the project can be owned by a utility, and at least 75% of the fuel must be from waste or renewable resources except in the case of cogeneration.
- 9) The utility is required to buy any power offered by the SPP at a rate geared to the utility's real benefit from the purchase, that is, the utility's full "avoided cost". The SPP can simultaneously sell its entire output to the utility at "full avoided cost" and buy all its needs from the utility at retail rates.
- 10) Computation of the buyback rate is based on the costs of energy or capacity or both to the utility, which, but for the purchase, the utility would generate itself or purchase from another source.
- 11) To the extent that a SPP can generate electricity at a lower cost than the utility's most expensive sources, it can require the utility to purchase its power at the utility's avoided cost.
- 12) Capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is unreliable. Similarly, SPPs are able to enter into contracts with each other. In this way they are able to increase the assured availability of capacity to the utility by coordinating scheduled maintenance and providing mutual back-up service.
- 13) Utility systems with high cost intermediate or peaking units and cheaper base load units must pay for electricity based on the savings of not utilizing their intermediate or peaking unit.
- 14) While PURPA requires the setting of purchase rates, this provision does not preclude negotiated agreements between SPPs and utilities.
- 15) The SPP may provide energy or capacity on an "as available" basis, without a legal obligation to deliver.
- 16) Since 1978, two-thirds of U.S. utilities have introduced conservation and demand reduction programs that offer lower kWh prices for industrial consumers who decrease their demand on the utility system. This move has provided further encouragement for SPPs -- particularly those employing cogeneration.
- 17) A SPP can require the utility with which it is interconnected to "wheel" its power to another utility that has higher avoided costs.
- 18) FERC has measured the success of PURPA by how little SPPs avail themselves of the rates, terms, and procedures laid down by state PUCs. Utilities are now willing to negotiate.

A.1 BACKGROUND TO U.S. ACTION PROMOTING DECENTRALIZED ELECTRICAL GENERATION

The economic and energy environment recognized by the U.S. government in 1977 lead to the drafting and eventual legislation of PURPA.

By the early 1970's, particularly after the oil crisis, it was apparent that major changes were occurring in the economics of electrical generation. Growth in demand was declining from a 7% annual rate experienced in the 1960's, to an average increase of 3% annually from 1973 to 1978. This drop in demand left utilities with unplanned excess capacity. In fact, the national average reserve capacity had doubled from the 20% normally maintained. These two developments made large-scale centralized generation far less attractive economically. Vast capital outlays and increasingly long lead times were required, necessitating highly speculative long-range demand forecasting. Capital costs were escalating, retail rates were rising and the financial community found utility investments less attractive.

In particular, due to inflation and to growing safety and environmental requirements and the associated regulatory delays, the capital costs for both coal and nuclear power facilities had escalated alarmingly.

At the same time, nearly half the U.S. electrical generation was fueled by oil and gas, and most utilities relied at least in part on this fuel type. Costs and oil imports became a major strategic concern of the public planners.

To address the changing energy environment, U.S. DOE mounted a monumental research & development effort in a number of alternative energy technologies, including products that would be appropriate for small power production.

Hundreds of small companies were spawned, producing a business constituency that quickly recognized the major institutional and market barriers that faced the new energy technologies. With mounting evidence that the U.S. utility sector was being squeezed by a continuing concentration on central generation facilities, many of these new companies began independent negotiations to build small

power production facilities. The utility sector resisted these attempts, leading the "new" energy industry to call for a legislative solution.

Advocates of PURPA pointed at several benefits of a decentralized approach to electrical production:

- * more efficient use of energy resources, particularly in the case of cogeneration.
- * enhanced use of renewable resources.
- * shorter lead times than for conventional, centralized facilities allowing market forces to drive the need for development of new generating capacity.
- * Greater flexibility for utilities to meet their primary purpose of distributing electricity in an efficient and least cost way.
- * Lower risks in public regulatory decision-making concerning the uncertain future of electricity demands.
- * Environmental benefits, including lower emissions.
- * Greater electrical system reliability due to the diversification of generation sources.
- * The development of competition in electrical generation, and the associated benefits of a free market approach including tapping new sources of risk capital.

Many utilities expressed doubts about the effect of privately owned small power production on overall system reliability and safety. Concern was also expressed about the effect on the overall energy market share of electrical utilities, and the relationship between gas, oil and electricity in the marketplace. Those utilities with excess capacity also questioned how beneficial decentralized electrical generation would be in terms of the short-term economies of their systems. The utility lobby indicated in no uncertain terms that a new regulatory scheme to promote the development of private electrical generation was both unnecessary and harmful to their interests.

Regardless, a majority of Congress felt that the changing economies of power generation would not in itself lead to decentralized development. Years of adherence to the concept of

large-scale generation geared to rapidly growing demand had led to the establishment of market and regulatory structures that created serious economic and institutional barriers to the development of small power production.

The utilities felt that state regulation of the monopoly in the distribution of electricity ensured the least cost and most secure supply of electricity for all customers. They felt that economies of scale justified only one company per regional zone and argued that they were in the best position to negotiate with potential small power producer's. In their view, therefore, there wasn't a need for legislative action. But control of distribution made the utilities impervious to allowing any form of competition in the production of electricity. They were able to control negotiation for the purchase of electricity from private sources by entering only into contracts that had significant benefit to the utility.

This control of distribution established the utilities in a monopsony position. Peter Brown of the Energy Law Institute contended in congressional hearings that monopsony occurs when a single buyer dominates the market and dictates the terms of purchase. He sighted examples of utilities in the northeast that claimed surplus capacity justified the low prices they were offering small hydro producers. But these same utilities continued to build central generation facilities to ensure continued excess capacity. Most potential SPP's were offered uneconomically low rates if, indeed, the utility offered any rate at all. Some utilities, in order to protect their own marketing of excess capacity, would not consider wheeling SPP generation to neighbouring utilities who would offer an economic price for electricity. When the SPP needed backup or supplementary power, they faced discriminatory rates. Brown contended that the response by utilities was a "logical economic result of their regulated monopoly/monopsony position. The goals of profit maximization and increasing market share, sanctioned by the regulatory authorities, also dictated these responses especially in the days when the economics so heavily favored centralized generation."

Utilities faced with excess capacity as a result of dropping demand were not interested in seeking new, small scale sources of power. Even for those utilities that saw long term potential in small power production, the institutional barriers made a receptive response impossible. Faced with all this, few new small power producers emerged. Furthermore, uncertainty as to whether the SPP would be treated as a utility and subjected to the same regulation, public scrutiny, controlled profits and administrative burden, discouraged potential decentralized generators. Legislation was seen as necessary.

B.1 PURPA: THE LEGISLATION AND HOW IT WORKS

The legislative solution to the institutional and economic barriers to decentralized electrical generation is contained primarily in Sections 201 and 210 of PURPA. The provisions, when considered in the context of the increasing costs of centralized generation, were intended to create a flourishing market for new, private small power production.

PURPA is a regulatory instrument that imposes the expected economic results of a simulated free market on utilities. A base of regulation was necessary to allow the economics to work and to encourage arms-length bargaining between SPPs and utilities. PURPA created a clear distinction between the utilities production and distribution functions.

While the intent of PURPA was clearly delineated in the legislative package, the Federal Energy Regulatory Commission (FERC) was given wide ranging authority in implementation. Following are the key parameters of PURPA.

B.2 The Qualifying Facility

To qualify as a SPP the total capacity of any facility cannot exceed 80 MW, no more than 50% of the project can be owned by a utility, and at least 75% of the fuel must be from waste or renewable resources except in the case of cogeneration.

In the case of cogeneration the only fuel requirement initially was that diesel fuel could not be used (see section A.2 in CHAPTER TWO). Cogenerators must also meet operating and efficiency standards established yearly by FERC.

B.3 Right to Interconnection

The SPP must pay the costs above and beyond the level which the utility would have paid to connect its own sources of electric supply to the grid.

The right to interconnect with the utility grid is critical to the effective right to sell electricity. Recognizing this, PURPA guarantees the right to interconnection provided that the cost is "fair and reasonable" and borne by the SPP.

B.4 A Guaranteed Market

The utility is required to buy any power offered by the SPP at a rate geared to the utility's real benefit from the purchase, that is, the utility's full "avoided cost".

Only during system emergencies or in unusual cases where the net effect of purchase from the SPP is to increase, not avoid costs for the utility, is the utility excused from accepting power. Typically, this would occur at very low load periods and the SPP's generation forced large baseload generating units to cut back, causing substantial start-up costs when demand forced them to step up production again.

This guaranteed market provides the major impetus for small power development.

B.5 Reasonable Rates for Power Purchases from Small Power Producers

PURPA provides that in requiring utilities to purchase electric energy from a qualifying facility, FERC must ensure that the rates for the purchase are just and reasonable to the electric consumers of the purchasing utility, nondiscriminatory to qualifying facilities, and that they not exceed the incremental costs of alternative electric energy. In interpretation of this order, FERC ruled that computation of the buyback rate would be based on the costs of energy or capacity or both to the utility, which, but for the purchase, the utility would generate itself or purchase from another source.

"Avoided cost" is based on incremental costs and not the average embedded costs of energy or capacity (which is used to determine retail rates).

So to the extent that a SPP can generate electricity at a lower cost than the utility's most expensive sources, it can require the utility to purchase its power at the utility's avoided cost, bringing potentially substantial profits to the SPP.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" and/or "capacity" costs. Energy costs are the variable costs associated with the generation of electric energy, representing the cost of fuel and some O & M expenses. Capacity costs are the costs associated with providing the capability to deliver energy, consisting primarily of the capital cost of generation facilities.

If by purchasing electricity from a SPP a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for purchase is based on those energy costs which the utility can thereby avoid. In addition, if the energy the SPP offers to the utility is of sufficient reliability and is legally enforceable, the purchasing electric utility will thereby be able to "avoid" constructing a new generation unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility. The rates for such a purchase are based on an "avoided capacity and energy cost basis."

The definition of "avoided costs" is key. State regulatory authorities are given the leverage to determine on a local basis, how avoided costs are computed. FERC recommended that both the fixed and running costs of an electric utility system which can be avoided by obtaining energy or capacity from a qualifying facility should be utilized for this computation.

While the State regulatory authorities are given the leverage to determine avoided cost within their jurisdictions, the computation must be based on the FERC guidelines.

FERC ruled that the calculation of avoided costs on a case by case basis would be time consuming, prohibitive and potentially expensive (if contested). The Commission (FERC) commented that "the computation of avoided costs in itself could inhibit the development of qualifying facilities." FERC has therefore required each State regulatory authority or nonregulated utility to arrive at standard purchase rates for facilities with a design capacity of 100 kW or less. The "standard offer" is reviewed on a yearly basis by the state regulatory authority.

The standard rates for purchases can also be applied to larger facilities, and these "standing offers" provide the basis for negotiations on larger facilities.

The quality of power produced by a particular technology (e.g. wind) must be considered by the states in establishing rates. The purchase price takes into account "the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system." FERC ruled that capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is unreliable. Similarly, SPPs are able to enter into contracts with each other. In this way they are able to increase the assured availability of capacity to the utility by coordinating scheduled maintenance and providing mutual back-up service.

In order to receive a capacity credit, the SPP need not enter into a long term contract. A utility's expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. For example, if the SPP agrees to deliver firm power for one year, it may enable the utility to avoid entering into a bulk power purchase arrangement with another utility.

If a utility has sufficient capacity to meet its demand and is not planning to add any new capacity to its system, then the availability of capacity from the SPP will not immediately enable the utility to avoid any capacity costs.

However, a utility with excess capacity may plan to add new, more efficient capacity to its system. If purchases from the SPP enable a utility to defer or avoid these new planned capacity additions, the purchase rate should reflect the avoided costs of the additions.

Utilities with excess capacity are still required to pay for electricity at the avoided cost. Utility systems with high cost intermediate or peaking units and cheaper base load units must pay for power based on the savings of not utilizing their intermediate or peaking units. (See discussion in Chapter 4)

FERC rules allow different "standard offers" for various technologies. If the utility system peak demand occurs when there is bright sun and little wind, for example, rates for purchase usually provide a higher capacity payment for solar electric (photovoltaic) projects than for wind.

While PURPA requires the setting of purchase rates, this provision does not preclude negotiated agreements between SPPs and utilities which differ from the rates, terms, or conditions in the standard offer. The ability to negotiate in "good faith" is anchored by the requirement that "standard offers" be used as the bench mark.

A SPP which enters into a long term contract to provide energy or capacity can negotiate to receive a greater percentage of the total purchase price during the first years of delivery, as long as the total payment over the duration of the contract does not exceed the total avoided costs.

FERC decided the SPP should have the option of selling the electricity either at a price determined by the avoided costs at the time of delivery or the avoided costs calculated at the time a term contract is signed. This ruling allows the SPP to establish a fixed contract price for its energy and capacity at the outset of its obligation or to receive the avoided costs determined at the time of delivery.

Further, the SPP may provide energy or capacity on an "as available" basis, without a legal obligation to deliver. The rates for such purchases are computed on the avoided costs at the estimated time of delivery.

The translation of the principle of avoided costs from theory into practice is an extremely complicated exercise and is substantially based on forecasting future occurrences. FERC has given the States and nonregulated utilities "flexibility for experimentation and accommodation of special circumstances" with regard to implementing purchase rates. Therefore, to the extent that an arrived at "avoided cost" does not provide sufficient buyback rates to encourage small power production, the simple computation of such buyback rates fulfills the requirements of PURPA. In such circumstances, SPP projects would likely not proceed.

B.6 Simultaneous Sale and Purchase

The SPP can simultaneously sell its entire output to the utility at "full avoided cost" and buy all its needs from the utility at retail rates. FERC has rejected utility arguments that it should require "net energy billing", wherein the meter is reversed and the utility or SPP is charged for the net amount sold or purchased.

This ruling gives a substantial additional incentive to SPPs who can purchase retail power at lower rates (based on the utility's average embedded costs) while selling to the utility at the avoided cost.

B.7 Backup, Supplementary, Maintenance and Interruptible Power Rates

Upon request, utilities must provide supplementary, backup, maintenance and interruptible power to the SPP on a "nondiscriminatory basis". Typically, utilities structure their retail rates to encourage the use of electricity. Charges per kWh decrease as consumption of kWh's increase.

PURPA recognized the standard utility pricing schedule as an inhibitor to on-site electrical generation. As a requirement of the legislation, the SPP is protected from an increase in unit charges from the utility, even with a significant drop in the SPP's utility demand.

In implementation, most state regulatory agencies have required utilities to supply power to the SPP at the "best available" rate.

Since 1978, two-thirds of U.S. utilities have introduced conservation and demand reduction programs that offer lower kWh prices for industrial consumers who decrease their demand on the utility system. This move has provided further encouragement for SPPs -- particularly those employing cogeneration.

B.8 Wheeling

Wheeling is the transmission by a utility of power generated within its service area, to another utility or industrial customer outside its service area. A SPP can require the utility with which it is interconnected to "wheel" its power to another utility that has higher avoided costs.

The SPP is responsible for any wheeling charges, although the wheeling utility may pay part or all of these costs. If a utility chooses not to wheel or if the SPP does not agree to the wheeling, that utility retains its obligation to purchase from the SPP.

B.9 Utility Filing Requirements

All utilities are required to supply data for the computation of avoided cost. Listed on the following page are three tables which delineate the filing requirements for each class of utility.

TABLE 1
REQUIRED DATA FOR UTILITIES' AVOIDED COST OF ENERGY

Utility Size	Level of Purchase from Qualifying Facility(ies)	Unit of Cost	Consumption Periods	Years Reported
Each utility system with a peak demand of 1000 MW or greater	Blocks of not more than 100 MW	¢/kWh	Daily — peak — off peak Seasonal — peak — off peak	Current calendar year Each of the next 5 years
Each utility system with a peak demand of less than 1000 MW	Blocks of not more than 10% of system peak demand	¢/kWh	Daily — peak — off peak Seasonal — peak — off peak	Current calendar year Each of the next 5 years

* Required by PURPA § 210 of all utilities with sales of at least 500 million kWh annually. Utilities with sales greater than 1 billion kWh annually must have reported these data by November 1, 1980. Utilities with annual sales of between 500 million and 1 billion kWh must report by June 30, 1982.

TABLE 2
DATA FOR UTILITIES' PLANS AND COST*

Capacity Type	Amount	Cost of Completion	Energy Costs	Frequency of Cost Calculations
Capacity additions	by individual generating units	\$/kW	¢/kW	Each year for the next 10 years
Capacity purchases	by individual planned firm purchases	\$/kW	¢/kW	Each year for the next 10 years
Capacity retirements	by individual generating units			Each year for the next 10 years

* Required by PURPA § 210 of all utilities with sales of at least 500 million kWh annually. Utilities with sales greater than 1 billion kWh annually must have reported these data by November 1, 1980. Utilities with annual sales of between 500 million and 1 billion kWh must report by June 30, 1982.

TABLE 3
DATA REQUIRED FROM UTILITIES OF VARIOUS SIZES

Utility Size	Data Required	Date
Sales of less than 500 million kWh/year	Data sufficient for a QF to figure avoided cost	On a QF's Request
if all-requirements	Data from supplying utility; own purchase price	On a QF's request
Sales of between 500 million and 1 billion kWh/year	Detailed requirements	June 30, 1982; then at least every 2 years
Sales greater than 1 billion kWh/year	Detailed requirements	November 1, 1980; June 30, 1982; then at least every 2 years

Even with utilities who are promoting the development of small power production, the computation of avoided cost is a contentious issue. In the negotiation process, whether directly between the SPP and the utility, or before the State regulatory agency, the cost data which a utility files is regularly challenged.

B.10 Interaction With PUC Regulation

The SPP has the option to avail itself of the State regulatory agency's prescribed terms and conditions or to negotiate independently. Negotiations have the advantage of allowing for the structuring of contract terms and conditions to meet the specific needs of both the SPP and the utility. The purpose of PURPA is to create certain guaranteed market results for the SPP if fruitful negotiation does not take place with the utility.

PURPA shifts the burden of non-agreement from the SPP to the utility. The SPPs often negotiate long-term contracts with utilities with rates that are below the State Regulatory Agency's "standard offer", because the possibility of regulatory changes and the lack of assurance that a specific purchase rate will be maintained create an uncertainty disruptive to financing.

FERC has measured the success of PURPA by how little SPPs avail themselves of the rates, terms, and procedures laid down by state PUCs. Utilities are now willing to negotiate.

B.11 Exemption From Regulation As a Public Utility

The exemption applies to all cogenerators but is limited to a 30 MW size for other small power producers. If the SPP meets this general requirement, they are exempt from all provisions of the Federal Power Act and from state laws and regulations governing the rates, finances and organization of their businesses.

A major aspect of the exemption is the exclusion of SPPs from the definition of "electric utility company" in the Public Utility Holding Company Act of 1935. The intent was to avoid deterring small power producers by the simple administrative burden of regulation.

B.12 Enforcement Procedures

FERC is given a broad mandate to review the actions of SPPs, utilities, State regulatory authorities, Federal agencies and non-regulated utilities.

FERC can be asked by any party to conduct a review on any issue pertaining to PURPA. The Commission has the sole right to determine whether action on its part is justified.

The final arbitrator on any issue is the Federal judicial system.

C.1 CONCLUSION

PURPA established a sound framework for State implementation of decentralized electrical development. Given the increasing demands of considering SPP complaints on a case-by-case basis, the legislation resolved many troublesome issues that would have plagued State regulatory agencies indefinitely.

CHAPTER TWO

IMPLEMENTATION
AND
INTERPRETATION OF
PURPA

CHAPTER SUMMARY

- 1) Nearly all SPPs obtain a FERC ruling. To prove that a project meets the ownership, fuel and size requirements, a small power producer must submit a documentation form to FERC (See APPENDIX A).
- 2) While giving State regulatory agency's considerable latitude in computing "avoided cost", FERC continues to insist that the "definition" must be based on the most recently constructed utility generation facilities.
- 3) By mid-1982, all states had met the requirement to determine the basis for avoided costs. Hearings concerning specific avoided costs for particular utilities are ongoing.
- 4) State authorities may establish standards to ensure the safety and reliability of interconnected systems. If such standards are established, they must be reasonable and the conditions necessitating the standards must be specified to FERC.
- 5) On April 24, 1979, the State of Mississippi and its Public Service Commission filed suit in federal court requesting a declaratory judgement that PURPA was unconstitutional.

In June, 1982 the Supreme Court upheld the constitutionality of PURPA. Principal to the decision was the unanimous support of section 210 that mandates utilities to interconnect and pay "avoided cost" rates.

- 6) On June 18, 1981 FERC issued a rule allowing diesel and dual fuel cogeneration facilities to obtain qualifying status generically.
- 7) On May 16, 1983 the Supreme Court ruled that FERC did not act arbitrarily or capriciously in promulgating the full avoided cost rule, ending the uncertainty which had plagued contract negotiations.

Following are the key interpretation, judicial and regulatory issues that have been raised as a result of PURPA.

A.1 FERC IMPLEMENTATION

To review, PURPA provides a legislative base for independent negotiation between the SPP and the utility. The Federal Energy Regulatory Commission (FERC) reiterated the arguments supporting PURPA in a "regulation update" printed in the U.S. Federal Register of February 25, 1980:

"In the past, potential small-scale power producers and cogenerators who wanted to interconnect with utilities and even out their power loads have run up against two major roadblocks. First, some of the electric utilities approached balked at purchasing power from small-scale producers and have even cut off sales of power to those who generate their own. Other utilities have only offered highly unfavourable buy-back rates, set so low as to eliminate any incentive to try to interconnect, or they have attempted to establish service rates with special surcharges that would have wiped out any savings by on-site production ... Second, by selling electricity, a small power producer or cogenerator has run the risk of being ruled to be a public utility, and thus subject to the burdens of state and Federal utility regulation of rates and financial organization (with the rules announced) purchases of energy or capacity from qualifying facilities will only occur when the cost to the qualifying cogenerator or small power producer of producing the energy or capacity is lower than the utility's avoided costs. Only if this is the case will payment by the utility of its avoided costs provide economic benefit for the cogenerator or small power producer."

FERC required that state regulatory authorities determine buy-back rates based on a utilities' "incremental costs". This action on the part of the state regulatory authorities was to provide a floor price, rather than specific contract terms and conditions.

A.2 FERC Amend's Ruling on Cogeneration Facilities

Initially, diesel was the only fuel which could not qualify as a new generation facility. In June 1981, FERC amended this rule to include diesel and dual fuel cogeneration facilities after the filing of an Environmental Impact Statement.

A.3 FERC Ruling on Certification of a Qualifying Facility

Certification of a QF (qualifying facility) is done directly by FERC. If the SPP is confident that a project meets the overall requirements of "qualifying", there is no need to apply to FERC for formal certification. This, however, leaves the SPP open to challenge by the utility or state regulatory body. In practice, therefore, nearly all SPPs obtain a FERC ruling. Simply stated, to prove that a project meets the ownership, fuel and size requirements, a small power producer must submit a documentation form to FERC (See APPENDIX A). The intent is to keep the certification process as simple as possible.

In keeping with President Reagan's policy of having those benefitting from government services pay for the costs incurred, FERC filed notice in September, 1982 that fees should be charged for PURPA related work. The Commission proposed that a SPP filing for qualifying status would be charged \$2,600 while utilities could be charged up to \$57,400 for hearings into interconnection, rate schedules or wheeling issues.

As of March 15, 1985 the "proposed" pricing schedule has not been acted upon. A "no-charge" policy remains in effect for all FERC-related PURPA functions.

A.4 Defining the nature of electric utility system cost data for calculation of avoided cost.

Each state regulatory agency is directed to determine the nature and extent of the electric utility system cost data upon which avoided costs will be calculated. Stipulating that an "incremental or marginal cost" basis will be used for computing avoided costs, the standard defined by FERC was the maximum allowed under PURPA. The rules include both the fixed and the running costs of an electric utility system which can be "avoided" by obtaining energy or capacity from a qualifying facility.

While giving State regulatory agency's considerable latitude in computing "avoided cost", FERC continues to insist that the "definition" must be based on the most recently constructed utility generation facilities.

FERC's intention is to give the SPP the maximum benefit possible.

The directive to the state regulatory agencies was tabled in March 1979, setting a deadline of March 20, 1980 for compliance. Only California, New Hampshire, Idaho, Wisconsin, New York and Texas met the filing requirement while Vermont, Pennsylvania and Virginia followed in June of 1980. Several other states, most notably Louisiana and Mississippi informed FERC that they refused to hold public hearings "on this matter".

By mid-1982, all states had met the requirement to determine the basis for avoided costs. Hearings concerning specific avoided costs for particular utilities are ongoing.

A.5 Setting Rates and Terms for Purchases by Utilities

For all qualifying facilities whose construction commenced after the passage of PURPA, state authorities must set rates for the purchase of power by electric utilities equal to the avoided cost to that utility of having to self-generate or purchase the power.

Since discretionary powers in setting rates for the sale of electricity by utilities are generally reserved for States, considerable state regulatory action was required to set rules for the purchase of energy by utilities.

Although Section 210 of the Act does not specifically give FERC the power to order utilities to interconnect with qualifying facilities, FERC argues that this power is implicit in its role of regulating the transactions between qualifying small power facilities and utilities. But for this implied interconnection power, interconnection would require a evidentiary hearing under the Federal Power Act.

Utilities are permitted to offer differential rates of purchase depending on the SPP's technology.

FERC dismissed numerous requests by utilities for a "splitting-of-the-savings." The Commission ruled that the intent of PURPA was to encourage SPP's and felt that if the marginal cost fraction was shared, the financial incentive would be less and thus discourage small power producers from interconnecting.

A.6 Setting Rates for Sales by Utilities to Qualifying Facilities.

Utilities are required to supply supplementary, back-up, maintenance, and interruptible power services. The rates for these services must be just and reasonable, in the public interest, and not discriminate against the SPP.

A.7 Miscellaneous Requirements and Options of State Regulatory Authorities.

A qualifying facility is to be held responsible for the costs of interconnection. The costs are payable directly to the utility. State authorities must determine the chargeable amount of these costs and the manner and time period for their reimbursement to the utility. In staff meetings of the Commission, utility representatives argued that the SPP should be able to obtain bank credit to receive funding for the interconnection. Failure to obtain such credit, utility representatives contended, would indicate that a SPP is too risky.

State authorities may establish standards to ensure the safety and reliability of interconnected systems. If such standards are established, they must be reasonable and the conditions necessitating the standards must be specified to FERC.

The state authority may apply to FERC for a waiver to all requirements (except the system cost data requirement) for any electric utility under its jurisdiction. Reliable utility system cost data in the public domain is seen as essential for negotiation to proceed "without prejudice". The Commission will grant such a waiver only when compliance with its rules can be shown to be unnecessary to the encouragement of small power generation.

State authorities can limit the degree to which SPPs are exempt from public utility regulations under state and federal law.

B.1 LEGAL CHALLENGES TO PURPA

The intention of PURPA was to encourage the development of independent electrical generation by removing inhibiting regulatory constraints identified in CHAPTER ONE, as well as to provide the framework for the encouragement of such small power development.

Section 210(b) of PURPA provides that in requiring utilities to purchase electric energy from a qualifying facility, FERC must ensure that the rates for the purchase are just and reasonable to electric consumers of the purchasing utility, in the public interest, nondiscriminatory to qualifying facilities, and that they not exceed the incremental costs of alternative electric energy (the costs of energy to the utility, which, but for purchase, the utility would generate itself or purchase from another source). Both utility and small power producer spokespersons agree that section 210 of the PURPA legislation did not adequately cover the parameters within which FERC would define the avoided cost question.

Richard Ottinger, former Congressman from New York and a key supporter of the legislation, felt that a more complete definition of "incentive rates" within the Act would have resulted in the total legislative package being declared unconstitutional in challenges before the courts. It was Ottinger's opinion that more specific rules would have resulted in an encroachment on "State's Rights", and therefore would be in violation of the Constitution.

B.2 State of Mississippi vs. FERC

On April 24, 1979, the State of Mississippi and its Public Service Commission filed suit in federal court requesting a declaratory judgement that PURPA was unconstitutional. The complaint attacked numerous provisions of PURPA, including requirements that state utility regulators consider federal ratemaking standards and provisions allowing DOE (FERC as the agent) or private parties (SPPs) to intervene in utility rate proceedings.

PURPA was attacked as being in violation of several constitutional provisions including the Tenth Amendment to the Constitution which protects "State's Rights".

The Plaintiffs argued that PURPA posed "an immediate threat because the Federal Energy Regulatory Commission has already begun enforcement ... and is publishing rules on cost of service reporting." Beyond the key principle of the case, that the Federal government had encroached on the state's jurisdiction, Mississippi felt the new provisions would require a more cumbersome regulatory process. The Public Service Commission stated categorically that they were satisfied with the existing rate schedule and utility filing procedure.

Mississippi won its case in the Circuit Court of Mississippi in February, 1981. Judge Cox struck down the requirement for state regulatory commissions to conduct hearings and consider fuel adjustment clauses, load management methods and seasonally adjusted rates when debating rate increases. The judge also ruled that the setting of interconnection standards and buyback rates was not required.

FERC filed an appeal directly to the Supreme Court within weeks of the Mississippi decision. The Commission argued that the "Commerce Clause" of the Constitution (encompassing the promotion of competition) preempted Mississippi's claim that PURPA was an encroachment on "State's Domain". Justice department lawyers acting on behalf of FERC in their brief to the Supreme Court stated that "Congress clearly can reach down into the states' affairs and, thus, does have jurisdiction over state regulation of utilities."

The Mississippi Circuit Court decision stalled implementation of PURPA in many states. Several state regulatory agencies adjourned hearings into avoided cost determinations pending the Supreme Court ruling.

In June, 1982 the Supreme Court upheld the constitutionality of PURPA. Principal to the decision was the unanimous support of section 210 that mandates utilities to interconnect and pay reasonable "avoided cost" rates. The court felt that this provision was "fair and justified".

The court was also in favour of the PURPA requirement that FERC would identify administrative and judicial procedures the states must follow in establishing ratemaking changes. The decision was close with a 5-4 vote in favour of FERC's position. Justice O'Connor authored the dissenting view arguing that the ruling "permits Congress to kidnap state utility commissions into the national regulatory family ... undermining the most valuable elements of our

federalism." Justice Blackman authored the majority position, calling Justice O'Connor's argument on state's rights "almost mystical". He added "the observations while argued as apocalyptic, and while striking, are over stated and patently inaccurate."

In ruling on the constitutionality of PURPA, the Supreme Court said that no issue as to interference with the state legislative function is implicated by PURPA because the states are free to "implement in an adjudicatory fashion, i.e., through case by case rate proceedings before the state public utility commissions."

As a result of this decision, the Public Service Commission of Mississippi began drafting its requirements. The rules are attached as APPENDIX B.

Hugh Stevens of the Mississippi PSC cautions that the challenge of PURPA by the state had little to do with small power production. "The Governor saw it as just one more example of Washington encroaching on an area that is a state responsibility. (The lawsuit) sent Congress a message ... in administering PURPA we've had far more flexibility than we first thought we would have."

Stevens feels that Mississippi has implemented PURPA in a way that "takes advantage of the good, and only holds the regulatory stick as a last resort. We did the best we could to clean up the problem areas given the latitude we were given. Our objective is as little interference as possible in the negotiations between the small power producer and the utility."

The state has set up a broad formula for estimation of avoided cost, and encourages the two parties to come to an agreement without the regulatory process. If an agreement cannot be reached, the Public Service Commission is willing to adjudicate and set the buy-back rate and other terms and conditions of the contract.

Stevens feels that arriving at an absolute computation of avoided cost is unnecessary:

"Kentucky and Ohio have written books on avoided cost. And both the utilities and small power producers are still disputing the result. The (Mississippi) Public Service Commission does not want to overly complicate the regulation of energy production in this state. We do not need to wield a big stick. The financiers are doing that. They have done more to encourage small power production than PURPA and every regulatory body in

this country has done. (The financial community) has recognized that (the economics of) small power development are better in investment terms, and we have recognized that as well by situating ourselves as the jury of last recourse."

Stevens adds. "We haven't had to make a single ruling yet. Both the independent producers and the utilities realize that it is to their advantage not to bring the matter before us. We set the parameters for the negotiation and they settle it amongst themselves."

B.3 American Electric Power Service Corporation vs. FERC

The subject of avoided costs and buyback rates was the primary motive for this challenge.

In January, 1981 American Electric Service Corporation launched an action in the Federal Court of the District of Columbia, arguing that FERC had not adequately justified its full avoided cost formula to enable the sharing of benefits between the independent energy producers, the utilities, and the ratepayer. The District Court and Federal Appeals Court agreed, but the decision was stayed pending a Supreme Court ruling on the matter.

Specifically, the court stated that it would expect FERC to consider a "percentage of avoided cost approach" under which, for example, FERC rules might call for 80% of avoided costs to be paid to the qualifying facility, with the rest of the avoided costs incurring to the benefit of the utility ratepayers.

Consolidated Edison of New York and Colorado-Ute Electric Association launched similar actions. In addition, they challenged the requirement that a utility must accept interconnection from all qualifying facilities. The appeal court ruled that the interconnection section of PURPA was "just and proper", but that the FERC rules on buyback rates were "discriminatory".

The triumverate of American Public Power Service Corp, Consolidated Edison and Colorado Ute joined forces for the Supreme Court hearing. As the defendant, FERC was joined by the Elizabeth Power Authority, American Paper Institute, Brooklyn Union Gas Company, Oxidental Geothermal, Windfarms Limited, Great Western Malting and Kerr-McGee Corporation as intervenors in the case.

On May 16, 1983 the Supreme Court overturned the decision of the D.C. and Appeals Court, ruling that FERC did not act arbitrarily or capriciously in promulgating the full avoided cost rule, ending the uncertainty which had plagued contract negotiations as a result of the original ruling of the D.C. Court. The ruling was 8-0 in favour with one Justice abstaining. The court also upheld a qualifying producer's right to demand connection to the utility grid. The full text of this landmark decision may be found in APPENDIX C.

The opinion of the court is brief. A FERC lawyer in an interview in the June, 1983 edition of Renewable Energy News commented on the ruling:

"The spirit of it, I think, is that the court didn't think there was much of an issue here. The Justices almost asked why the plaintiffs were up here, saying 'the commission (FERC) has appeared to do what it was supposed to, and we don't even understand why this case has gotten as far as it did.'"

Justice Marshall's decision stated:

"FERC did not act arbitrarily or capriciously in promulgating the full avoided cost rule which is the maximum rate permissible under section 210(b) ... Although FERC realized that the rule would not directly provide any rate savings to consumers, it reasonably deemed it more important at this time that the rule would provide a significant incentive to the development of cogeneration and small power production, and that ratepayers and the nation as a whole would benefit from the decreased reliance on scarce fossil fuels and more importantly, the more efficient use of energy."

With the question of whether full avoided costs is the appropriate standard for sales contracts settled, the implementation of the rule became the key issue for determining the economic viability of many SPP projects. Implementation of the "avoided cost" rule is reserved by the State regulatory authorities.

The court's decision was instrumental in helping SPPs in contract negotiations with utilities. "The beauty of what happened is that it gave the full club, the full leverage that one can use to get a utility to sit down with you and negotiate in good faith", Alan Hills of First Interstate Capital says. "What the small power producer wants is the kind of contract that is very financable, which has at least some type of floor-price mechanism, which has a long term contract, and one where they (utilities) have to take what you produce."

C.1 LEGISLATIVE ATTEMPTS TO CHANGE PURPA

While the Mississippi and American Public Power cases were being considered by the Supreme Court, two Congressional bills were tabled in April, 1982 to clarify PURPA.

Senator Gordon Humphrey (Republican - Rhode Island) tabled a Bill that would have removed the effective 50% ownership equity limitation for utilities and allowed them to own unregulated "qualifying facilities" covered by PURPA. His proposal was notable for its exacting detail. It included a clear delineation of the avoided cost methodology set by FERC and reaffirmed the mandating of interconnection. Of particular importance, in light of the Supreme Court challenges, was a provision that would allow a State to pass legislation exempting it from PURPA implementation.

Richard Ottinger (Democrat - New York) tabled a Bill in the House that covered the same areas as the Humphrey proposal. The only significant difference concerned the equity interests in qualifying facilities. Ottinger felt that allowing utility ownership would be a regressive move.

Both bills died as result of FERC's successful defence of PURPA before the Supreme Court.

D.1 FERC: ONGOING IMPLEMENTATION

FERC's role in the ongoing implementation of PURPA has been affected by the legal disputes.

While many parts of PURPA legislation required Commission action, PURPA did not absolutely define the role FERC should fill in the promotion of small power generation.

The concern about "State's Rights" has resulted in FERC instituting an arms length "enforcement of interconnection" policy under which enforcement is left primarily to the state commissions and courts. FERC has also said that "questions relating to a particular avoided cost methodology are typically matters for a State or local forum."

Requests to FERC by SPPs in both enforcement and avoided cost questions have been referred back to the state regulatory authorities. FERC has been willing to play a role in "wheeling" issues which it recognizes as being an intra-state issue.

Following, are descriptions of some of the rulings which FERC has made since the Supreme Court decisions.

D.2 Consolidated Edison's Challenge of Automatic Qualifying Status for Diesel and Dual Fuel Cogeneration Facilities.

Consolidated Edison has fought PURPA in the courts, before federal and state regulatory bodies, and in municipal government. The challenge of qualifying status for cogeneration facilities gives an indication of the arguments an "anti-PURPA" utility uses in such matters.

During the rulemaking proceedings implementing PURPA, FERC prepared an Environmental Assessment under the National Environmental Policy Act which determined that only diesel and dual fuel commercial cogeneration facilities in the Middle Atlantic Region had the potential to cause environmental problems. Therefore diesel and dual fuel cogeneration units were excluded from the benefits of PURPA, pending further investigation.

After completion of the full Environmental Assessment, FERC issued a final rule allowing diesel and dual fuel cogeneration facilities to obtain qualifying status generically. This rule was issued on June 18, 1981.

Con Ed applied for rehearing, asking for reinstatement of the interim exclusion from qualifying status for diesel cogenerators, claiming a number of deficiencies in the environmental assessment.

FERC's use of Con Ed's estimate of 562 MW of cogeneration development in New York City by 1995 was attacked on the grounds that Con Ed had based its' estimate on projected cogeneration development without PURPA-related rate or interconnection inducements.

Con Ed argued that the Commission had failed to take into consideration the socio-economic impact of cogeneration in New York City. The utility indicated their studies had concluded that for every 100 MW of load lost to cogeneration, a 0.7% increase in rates would result, since the fixed cost of excess generating capacity would be spread over the remaining customers.

Con Ed also contended that the Commission should have evaluated the tax effects of cogeneration. According to this utility, a reduction in its sales will result in reduced revenues from taxes collected by state and city authorities as a percentage of electric bills. Thus, Con Ed argues, the area's other taxpayers would have to absorb the resulting revenue losses.

These arguments while having little to do with environmental impact, are central to Con Ed's message to all parties interested in interconnecting with their grid system. They have effectively blocked development of small power production in a market area which, during the drafting of the PURPA legislation, indicated a great deal of potential. In at least four cases, cogenerators have become frustrated to the point of disconnecting from the Con Ed grid. Numerous economic applications for cogeneration have remained undeveloped because of the utility's recalcitrance.

In August, 1984, three years after Con Ed asked for a re-hearing on the rule allowing automatic qualifying status to diesel and dual fuel cogeneration facilities, FERC responded. The Commission openly stated that the notice for re-hearing had little to do with environmental assessment:

"NEPA (National Environmental Policy Act) does not require an agency to evaluate economic impacts that are not inter-related with the physical environment. In any case, the impact on rates, if any, would be a short term phenomenon, as even under Consolidated Edison's own filings, the utility will need more capacity by 1995."

"The impact on customers who do not generate any of their own electrical needs has been overstated by Consolidated Edison. When cogenerated electricity is used for the cogenerator's internal needs, the impact on the utility is the same as that of a conservation measure. Both may require a reallocation of demand costs due to a reduction in total kWh demands. Although, in the short term Con Ed may be inclined to increase its rates, in the long-term, Con Ed's customers will benefit from the more efficient use of resources."

FERC commented on the potential tax implications:

"Any conclusion from such an exercise would be based largely on speculation because of the inability to precisely estimate the degree of cogeneration development resulting from PURPA and the unforeseeable variables in state and city tax policy."

D.3 Enforcement Action Against Puerto Rico Electric Power Authority

Since the first application for qualifying status by a SPP, the Puerto Rico Electric Power Authority (PREPA) has made it a practice to intervene and challenge all such applications. At first, through imaginative efforts, it submitted a substantive challenge to each application. In one case, it claimed the applicant was a "utility" and therefore did not qualify. In another it claimed that the wrong applicant had filed; that rather than the owner the engineering firm should have filed.

In all cases, PREPA asked that the Commission abandon its automatic certification procedures for qualifying applicants in favour of case by case evidentiary hearings. PREPA also asked that all certification proceedings be held in abeyance pending its preparation of a petition for rulemaking.

On May 15, 1984, Roche Products filed an application for qualifying status for a facility in the PREPA service area, and PREPA intervened. The SPP filed a complaint with FERC for enforcement of the Commission's PURPA regulations. This is the first case on record of a SPP filing for "enforcement". Roche's contention was that because PREPA had refused to recognize even a single qualifying facility there was a question as to PREPA's "good faith."

Two other firms, Alcon, and Wind Energy Development Corporation who are also applying for qualifying status, recognized the restrictive attitude of the utility and joined Roche products in their action. Since Puerto Rico does not have a Public Utility Commission, and since there is thus no regulatory commission with jurisdiction over PREPA, the "filing for intervention" requested FERC action.

PREPA answered the complaint stating it was merely acting to protect its shareholders, small ratepayers and employees, and that it had no other available administrative remedy than to contest interconnection.

FERC ruled in November, 1984 that it would not initiate an enforcement action since PREPA had filed a report pursuant to FERC regulations describing how it would implement PURPA, and that the filing fulfilled the regulatory requirement of implementation:

"Questions relating to a particular avoided cost methodology and interconnection are typically matters for a State or local forum. Once nonregulated electric utilities have appropriately implemented the Commission's regulations, the Commission's role is limited regarding questions of proper application of these rules on a case by case basis."

Scott Spiewak, attorney for Roche Products, commented in the trade newsletter, Cogeneration and Small Power Monthly:

"It is easy for FERC to cite the above language in its enforcement policy and to recommend that Roche Products seek relief before the Puerto Rican courts. However, to do so (has played) into the hands of recalcitrant utilities. While investor-owned utilities may be subject to timely and effective enforcement action before the utility commissions, such timely and effective enforcement is unlikely in the courts. In fact, it is the historical failure of the courts to adequately deal with the complex issues arising in the field of utility regulation which led to the formation of state utility commissions and publicly held utilities in the first place. The courts, unaided by the expert determinations of an unbiased public utility commission, are simply not capable of assessing in a timely fashion such issues as the appropriate measure of avoided costs, or of whether supplementary, back-up and standby rates established for cogenerators are discriminatory. While normally, publicly owned utilities are not in need of regulation, with the advent of independent power generation by cogenerators and small power producers, these utilities are placed in a position where their decisions impact not only their customers, but also their competitors. When there is a demonstrable hostility to cogenerators and small power producers on the part of a publicly owned utility, the FERC should exercise its power to enforce the law. Failure to do so would leave cogenerators and small power producers to inadequate remedies before the courts, and in most cases, effectively exempt publicly owned utilities from PURPA."

D.4 Declaratory Order on Wheeling

On September 2, 1983, the Florida Public Service Commission requested FERC to rule on whether tariffs could be charged for

wheeling power from one utility to another by a SPP.

FERC ruled in November, 1984 that whenever power is wheeled, the Commission has total authority on tariff charges. However in the Florida case they rejected a wheeling tariff because of the short distance involved. The Commission stated that the courts had determined that transmission of electricity is considered interstate commerce, and therefore not subject to state regulatory authority. Excepting one grid in Texas, the heavy interdependence of all state grids with bordering state grids has warranted this action.

Most transmission of electricity in the U.S. is on interconnected state grids. It therefore falls under FERC authority, even if the wheeling takes place within a single state.

FERC noted it would give "great weight" to state determinations as to the appropriate rate to be paid for wheeling services.

In essence, FERC ruled that states had the authority to require the wheeling of power, even if they lack the authority to set rates.

The issue of wheeling is central to the continued development of small power production in the United States.

E.1 ANTITRUST ACTION

In determining avoided cost, the range in the United States is substantial - from slightly more than 1 cent per kWh in some parts of the midwest to over 9 cents in Maine. With increasing frequency, SPPs in utility service areas with low buyback rates are attempting to negotiate deals with outlying utility companies who will pay a greater price for the electricity. For this arrangement to work, the primary utility with which the SPP interconnects, is expected to "wheel" the power with "a fair tariff" to the utility who will pay "an economic price" for electricity. More often than not, because of its lower generation costs, the primary utility is already selling electricity to the outlying utility.

Many utilities in the United States are considered to be "service utilities" since the electricity they distribute in their retail area is purchased from another utility. This power can be bought on a firm contract basis or on an intermittent basis.

In a number of cases, these "service utilities" are captive customers. Since they have little choice other than building new generation facilities they must accept the terms and conditions of the selling utility in order to meet their retail obligations. The selling utility will normally act to protect its control of this market.

E.2 The Greensboro Lumber Case

Greensboro Lumber filed an antitrust action in August, 1984 against Georgia Power Company. The lumber company was offered what it considered to be an inadequate buyback rate by Georgia Power and the utility refused to consider a wheeling agreement. The case is expected to reach the courts sometime in 1986.

The argument supporting this suit stems from the case of the U.S. Justice Department vs. Otter Tail Power Co. in which Otter Tail was sued for refusal to wheel power from the U.S. Bureau of Reclamation to municipalities who wished to buy the power at retail price. Otter Tail was found to be in violation of antitrust laws, as it was attempting to extend its monopoly as a transmission company into a monopoly in retail power sales.

According to Melanie Cutler, chief of the energy sector in the antitrust division of the Justice Department, there are at least three different classes of activity which might compose anticompetitive behaviour on the part of a utility:

- 1) Refusal to purchase power, thereby acting as a "bottleneck" to commerce in electric power.
- 2) Refusal to provide supplementary, backup or maintenance power to a small power producer who is not selling power to the utility. The theory behind this is that even a single facility may be a "market" for antitrust purposes, and interference by the utility with potential competition from its own customer could violate the antitrust laws.
- 3) Refusal to wheel power.

F.1 OTHER ISSUES

Beyond the property tax issues discussed in section C.2 of this chapter, municipal zoning regulations, contract law, and environmental concerns have all been raised as a result of the encouragement of small power production facilities in the United States.

Addressing each of these concerns is beyond the scope of this study, although some will be mentioned in the RECOMENDATIONS section.

CHAPTER THREE

CAPITAL MOBILIZATION
FOR
UTILITY
AND
SMALL POWER PRODUCTION
PROJECTS

CHAPTER SUMMARY

- 1) In the United States, the financial condition of utilities has deteriorated in response to general inflation, enormous increases in fuel costs and interest rates, and major power plant construction programs which have become increasingly expensive. Investors no longer view utility stocks as the premium investment they once were. Bond issues are being scrutinized with increasing care.
- 2) Several major brokerage firms, including Merrill Lynch, First Interstate Capital, Morgan Stanley, Hambrecht & Quist and Prudential Bache have indicated their recognition of the economic advantage of utilities pursuing ambitious conservation and alternative energy programs by recommending the purchase of that utility's stock.
- 3) By a variety of financial measures, investor-owned utilities in the United States are in poor shape. Stocks are generally selling at 70 to 85 percent of book value. Real earnings are down, generally below authorized rates of return. Cash flows are poor and assets-to-debt ratios are declining.
- 4) Utility companies building nuclear plants display consistently lower ratios than other U.S. utilities.
- 5) Merrill Lynch feels that "utilities who are reluctant to approach their planning needs from a full energy service corporation orientation, who continue to concentrate on the development of centralized generation facilities, will potentially have an unusually costly unused capacity, and thus should be approached with caution."
- 6) The rate-of-return expected from SPP projects now stands at the mid point of the range generally used for utility financing.
- 7) Small power generation projects are almost exclusively financed on a project basis. While the viability and experience of the small producer are important factors in obtaining financing, the economics and security of a specific project are the key determinants.
- 8) The decision whether to invest in small power production is dependant upon the availability of sites, investment tax credits and rapid depreciation write-offs, and the availability of small issue tax exempt industrial development bonds.
- 9) Even with the security of Canadian utility investment, the U.S. financial community is looking closely at specific projects they are being asked to finance.



Introduction

The factors affecting the availability of capital can be divided into two basic areas. First the character and course of the capital markets themselves and second the risk profile of the particular investment or loan. The underlying theme is that the higher the perceived risk, the greater the reward demanded. If the perceived risk is too great, no potential reward will serve as sufficient enticement.

The purpose of this chapter is to examine the attitudes of U.S. financial markets towards capital mobilization for large utility projects as compared to small power production projects.

A.1 U.S. UTILITY FINANCING: A GENERAL ASSESSMENT

Traditional utility investors are risk adverse. Over the last decade numerous project failures in the U.S. utility industry have sent shock-waves through the investment community, affecting both debt (bonds) and equity (stocks) financing.

On the bond side (financing new capital projects), utility investors are demanding a higher rate of return, and wide ranging risk support clauses. While a bond issue will have a specified purpose, it is issued generally on a corporate basis rather than on a project basis. If a project does not create its own income to meet the repayment of the bond, the investor has the security of the utility's overall infrastructure to fall back on.

If there are financial problems with a bond-funded utility project, there will be an impact on the other side of private utility financing - the sale of stock. Several major brokerage firms, including Merrill Lynch, First Interstate Capital, Morgan Stanley, Hambrecht & Quist and Prudential Bache have indicated their recognition of the economic advantage of utilities pursuing ambitious conservation and alternative energy programs by recommending the purchase of that utility's stock.

The Franklin Research and Development Corp. supports this view in its investment newsletter Insight, the FRDC calculates that stock

prices of the ten utilities with the highest expected alternative energy reliance by 1992 rose an average 250% faster over the last ten years than those of the largest coal-burning power companies.

"Lower capital costs, faster start-up time and construction flexibility for alternative energy production will put the alternative-using companies in a more profitable position in an era of uncertain consumer demand and increasing environmental constraints."

The report predicts that renewables will supply 15% of the United States' electricity needs by the year 2000.

A.2 Reasons For Concern

In the United States, the financial condition of utilities has deteriorated in response to general inflation, enormous increases in fuel costs and interest rates, and major power plant construction programs which have become increasingly expensive. The utility sector's commitment to large construction programs planned fifteen years ago but constructed in the late 70s and early 80s when inflation and interest rates were at record highs, struck a serious blow to this sector.

Investors no longer view utility stocks as the premium investment they once were. Bond issues are being scrutinized with increasing care.

Large conventional generation facilities take from seven to ten years and longer to plan and construct. They are generally financed through the sale of bonds and, for investor-owned utilities, through a combination of bonds and stock sales. During construction, the utility is obliged to pay interest on the bonds and dividends to stockholders, without receiving revenue from the investment during the first seven to ten years.

In 1971, U.S. utilities were able to raise capital for new construction programs at an average interest rate of slightly under 6 percent. By 1981, this average increased to nearly 16 percent, making construction of new power plants extremely expensive.

By a variety of financial measures, investor-owned utilities in the United States are in poor shape. Stocks are generally selling at 70 to 85 percent of book value. Real earnings are down, generally below authorized rates of return. Cash flows are poor and assets-to-debt ratios are declining.

How big an impact do financing charges play on the total cost of a new generating facility? According to Securing California's Energy Future, the 1984 annual report of the California Energy Commission, if a project takes 5 years to build and money for construction is borrowed at 10 percent interest, about 15 percent of the plant's total cost will be in interest. If the construction time is extended to 7 years, interest rises to 27 percent of total costs. If the construction time is 10 years, interest rises to 46 percent of total costs. Utility construction is financed by the sale of bonds and for investor-owned utilities, through a combination of bonds and stock sales. During construction, the utility is obligated to pay interest on the bonds and pay dividends to stockholders, from existing revenue producing generation plants. The interest on construction work in progress (CWIP) has a substantial impact on the financial viability of both public and private electrical utilities.

One of the most expensive power plant projects cancelled after considerable construction was situated in the Pacific Northwest. The Washington Public Power Supply System (WPPSS), a joint venture of Northwest public utility districts and cities, was constructing five large nuclear power plants. WPPSS offered participation to cities, public utility districts, and cooperatives throughout the Northwest. In January of 1982, WPPSS management cancelled two of the planned five units because of cost increases, financing problems and low electricity demand growth rates. In the fall of 1983, the entire project was mothballed and WPPSS was unable to meet its obligations to bondholders.

The standard financial ratios used to rate a utility's credit indicate nuclear power's diseconomy of scale. The ratio of earnings to interest payment, measured in a variety of ways, indicates the extent to which a bondholder is assured of payment. Utility companies building nuclear plants display consistently lower ratios than other U.S. utilities.

Alex Radin of the American Public Power Association, an organization representing 1,750 local publicly owned distribution utilities, commented on the private utility sectors approach to building new generation at the association's 1981 conference:

Inclusion of the costs of work in progress by private utilities in our rate base is like the federal government requiring every American to begin paying now, in 1981 dollars, for a 1992 Chrysler -- despite the fact that you may not want a car, might not be around in 1992 to drive it, and have no assurance that the car will even be produced. With (the private utilities) approach, if the car does show up, you get no ownership rights and Chrysler charges you to rent a ride.

A 1983 publication by Merrill Lynch, entitled Outlook for Alternative Generation Financial Techniques, advised financiers to invest in utilities who are purchasing electricity from decentralized generation facilities:

In evaluating utility investment, investors should look for flexible management which is willing to use a variety of resources to solve power generation problems ... and to assess management aggressiveness with regard to the development of alternative technologies ... Widespread conservation, and decentralized power production leading to lower than expected load growth will bring a competitive advantage to those utilities taking this option. We feel that utilities who are reluctant to approach their planning needs from a full energy service corporation orientation, who continue to concentrate on the development of centralized generation facilities, will potentially have an unusually costly unused capacity, and thus should be approached with caution ... We believe that investors and consumers alike will be well-served by progressive utility managements which blend alternative technologies and conservation measures into their power generation program, and which utilize those innovative financing techniques which result in making the best of a difficult market environment.

Financial analysts have discovered that projects which can be built rapidly have low interest costs and can be added to the rate base quickly. Hugh Devlin of the investment banking firm, Morgan Stanley and Co. in a November, 1984 newsletter to the firm's clients indicates a growing trend in the U.S. financial community:

In 1980 Southern California Edison announced a major corporate commitment to conservation, alternative, and renewable resource-based technologies. These technologies have short lead times, can be built in small units to match demand growth, and allow a utility to begin earning almost immediately on its investment. Since that time SCE's financial picture has improved dramatically. SCE's common share price recently reached a ten-year high following a good earnings performance in 1983. The market-to-book ratio for SCE stock is approaching unity, reflecting their ability to earn near their authorized rate of return. There is a strong indication that the investment community perceives their change in planning policy away from high risk, long construction time projects to alternatives as a step in the right direction ... We recomend an aggressive buy.

There is general agreement in the financial community that the restriction under PURPA limiting utility ownership to 49% in small power production projects, has limited the acceptance of the decentralized generation option by utilities. "Of course", says Alan Hills of First Interstate Capital, "inertia has probably been a bigger reason."

U.S. utilities presently face a turning point in their planning. They have the option of returning to long lead time, large, and expensive power plants, or they may elect to increase the use of conservation and privately financed, renewable energy and conservation based technologies. Utilities cannot simultaneously finance both approaches. Merrill Lynch, First Interstate Capital, Morgan Stanley, Hambrecht & Quist and Prudential Bache all indicate they are leaning towards the small power production option.

B.1 FINANCING SMALL POWER PRODUCTION

Generically, Wall Street recognizes that small power development has the advantage of diversity, flexibility and modularity, but the disadvantage of unproven technologies generally developed by small businesses with limited experience in interconnection.

Modularity facilitates equipment additions in much smaller units than is common with conventional technologies. Shorter lead times for adding modular increments reduces uncertainty in planning, and allows incremental capital outlays over shorter periods of time. Hence the financing of SPPs compares favourably with utility bond and stock issues.

Ed Blum of Merrill Lynch Pierce Fenner and Smith, Inc. states the financial market's criteria when backing both utility and SPP generation projects:

It comes down, simply, to a matter of risk. On the one hand you have utilities who can finance on a corporate basis, while the small power producer usually develops on a project basis. The market is scrutinizing each option much more intently than you would have seen ten years ago. General utility bonds are seen as being riskier, therefore investors are demanding a greater rate of return. On the other hand, small power development was virtually ignored ten years ago. But today, there is a lot of interest in this investment because the industry now has a track record.

Blum feels the rate-of-return expected from SPP projects now stands at the mid point of the range generally used for utility financing. On the high end, the refinancing of the Seabrook project required a 21 percent interest rate while a new bond series for Southern California Edison pays 13.1 percent. "For small power projects, the established companies with a few projects under their belts, the deals are structured to pay about 16 percent. New companies, like any new entity coming to the market, have to structure their deals to pay more", says Blum. This view was substantiated by representatives from other financial institutions.

Peter Metzner of General Electric Credit Corporation stresses the importance of contained risks:

We are interested, exclusively, in financing alternative energy projects that produce outputs for which there are clearly identified, existing and stable markets. In practical terms this means that we look for long term power sales contracts, a favourable regulatory climate and proven technologies

While the viability and experience of the small producer are important factors in obtaining financing, the economics and security of a specific project are the key determinants. A G.E. Credit cogeneration project illustrates this point.

The Great Lakes Carbon Corporation has a plant in Port Arthur, Texas, that produces purified carbon from petroleum coke. The plant generates waste heat equivalent to 2,800 barrels of oil per day. The developer, Power Systems Engineering, purchases the waste heat, converts it to 400,000 lbs of high quality steam, and sells steam to Gulf Oil and electricity to Gulf State Utilities.

Metzner points out the key difference between project and corporate financing:

Power Systems Engineering is a closely-held design and engineering firm whose net worth is only a fraction of the value of the project. Obviously, this company could not begin to qualify for a \$70 million loan or lease. So, the project had to stand on its own feet economically. (G.E. Credit) provided a construction loan and a single investor lease. Neither was dependent on the firm's credit rating since the project's credit support comes from the long-term agreements with Great Lakes Carbon, Gulf Oil, and Gulf States Utilities.

Beyond the consideration of the marked distinctions in risk profiles, renewable resources are just another electric source to the finance community. The decision whether to invest in small power production is enhanced by the availability of sites, investment tax credits and rapid depreciation write-offs, and the availability of small issue tax exempt industrial development bonds.

From a project financing standpoint, the key issues are essentially left to the state regulatory agencies: the availability of contracts and capacity credits, intrastate wheeling, and enforcement of good faith development and negotiation of rates.

In a new industry, investment flows into those markets that provide additional financial and institutional encouragement to small power production, beyond the base that PURPA provides. California is a classic example of a market area that has both the resource base and political will to develop the small power production market. These extra factors include:

- * state level tax incentives that enhance the attractiveness of investment in relation to other states.
- * residents with taxable incomes higher than the national average, and the potential to take full advantage of the tax measures as investors.
- * a Public Utility Commission and state Energy Commission that has created and enforced the most favourable regulatory climate for small power production in the United States. (Over 100 legislative initiatives enacted to accelerate private investment in small power production technologies.)
- * a geographic region that has a substantial conservation and renewable resource base.

C.1 U.S. UTILITY FINANCING AND THE IMPACT ON CANADIAN UTILITY FINANCING OF NEW GENERATION

Canadian Utilities are financed on the same corporate basis as their U.S. counterparts. The U.S. financial community views investments in Canadian utilities in favourable terms because of their inexpensive hydro resource base and the backing they receive from their provincial governments. Provincial guarantees virtually eliminate any fear of risk on the part of the U.S. investor.

Even with these strengths, however, there are three general concerns:

- * the way in which Canadian utilities are used as fiscal instruments of provincial governments for major generation developments and restrictions on rate increases.
- * the increased importance from the Canadian point of view of selling electricity to the United States while a growing movement both in Congress and the U.S. nuclear and coal industries, towards restricting such foreign purchases.
- * Since financing is computed in terms of U.S. dollars at the time of investment, the recent decline in the value of the Canadian dollar is significant.

It is worth repeating that provincial guarantees are the dominant factor in Wall Street's willingness to invest in Canadian utilities. While not mentioned by those surveyed, the Canadian track record in planning and building central generation facilities is also a factor which contributes towards greater creditworthiness for Canadian utilities as compared to their U.S. counterparts.

Even with the security of Canadian utility investment however, the U.S. financial community is looking closely at specific projects it is being asked to finance. Just as it has become a more active participant in U.S. utility planning, the financial community is now also making Canadian utilities aware of its concerns.

CHAPTER FOUR

UTILITIES
EXPERIENCE
WITH
PURPA

CHAPTER SUMMARY

- 1) Generally, U.S. utilities are now beginning to accept their new partnership in electrical generation.
- 2) The common problem faced by electricity planners is how to deal with uncertainty in forecasting demand. Small power production has helped public planners confront this uncertainty.
- 3) There are four different methods used to compute avoided costs. These are:
 - * the short-run marginal cost approach.
 - * the peaker approach.
 - * the system planning approach.
 - * the long-run differential revenue requirement approach.
- 4) In 1983, summer peak demand in the United States was 40% lower than project a decade earlier.
- 5) U.S. utilities will be cutting their construction requirements by at least \$45 billion over the next decade because of increased reliance on third party developed small generation facilities, conservation and load management.
- 6) Although not entirely due to PURPA, in 1982, U.S. utilities purchased 3,508 MW, from SPPs. By 1992 the figure is estimated to reach 12,547 MW, and by 2000 small power producers should contribute at least 30,150 MW. The major utilities purchasing electricity from SPPs in 2000 will be Pacific Gas and Electric, Southern California Edison, Houston Lighting and Power, Public Service Company of New Mexico, Virginia Electric Power, Gulf State Utilities, Tennessee Valley Authority, and Carolina Power and Light.
- 7) Privately developed small power generation has transferred the risk of new technologies out of the utilities domain and has helped utilities develop smaller increments of capacity. Each of the utilities surveyed felt there were existing inequities in the current law governing small power production in that it discriminates against utility investment and development.

Introduction

The electric utility response to PURPA and third party owned generation has ranged from strong resistance to qualified support. Interviews were conducted with Southern California Edison, Pacific Gas & Electric, San Diego Gas & Electric, Central Vermont, Cincinnati Gas & Electric and Consolidated Edison. Further information on other utilities was drawn from the literature review.

A.1 UTILITIES AND PURPA

California utilities have the most experience working with small power producers. Central Vermont and Cincinnati Gas & Electric have more limited experience than their California counterparts, but are planning for greater participation with SPPs in the late 1980s. Consolidated Edison continues to prevent SPP interconnection, through a variety of legal avenues.

Each of the utilities contacted identified a common fear when PURPA was passed. They were unsure of the implications of small power generation on their businesses. Generally, U.S. utilities are now beginning to accept their new partnership in electrical generation.

In practical terms, the perceived "anti-utility" sentiments contained within the PURPA legislation have not resulted in the highly confrontational implementation that was anticipated by the utilities. In fact, except in California and some parts of Texas, the rush to interconnect has been far less extensive than utilities first expected, allowing for the orderly integration of private capacity into their planning.

U.S. utilities are extremely concerned about the rising cost of central generation while still unsure about the technical reliability of the new small power technologies. Most importantly, the common problem faced by electricity planners is how to deal with uncertainty in forecasting demand. Small power production has helped public planners confront this uncertainty since SPP projects can be brought on line within two years. This permits more accurate planning of electricity supply requirements.

A.2 Determination of Avoided Costs

Douglas Bauer, Senior Vice-President of the Edison Electric Institute states:

We have a deep vested interest in developing those resources that will avoid us having to build central plants ... coal or nuclear. It is increasingly clear that the modularity of small power development is highly compatible with the current needs of the electric utility industry ... But we are concerned about some of the existing inequities in current law governing small power production. These include the fact that the full avoided cost is sometimes in excess of the utilities true avoided cost ... We would identify the present California and particularly the New York prices as above true avoided cost. In California marginally, in New York excessively.

PURPA provides the framework for selling power by SPPs at "full avoided cost", but leaves it to each state to determine precisely what full avoided costs means. Most states, with the exception of California, have failed to define what avoided costs payments should be, leaving it to the utility to make the first offer and to the small power producer to negotiate if they think it is too low.

The study Cogeneration: Regulation, Economics and Capacity, prepared by Resource Dynamics Corporation for the Energy Information Administration found there are four different methods used to compute avoided costs. These are variously used individually or in combination. These methods are:

- * the short-run marginal cost approach.
- * the peaker approach.
- * the system planning approach.
- * the long-run differential revenue requirement.

Since each yields different results, the price offered to SPPs depends on the method used.

The short-run marginal costs approach generally reflect only those changes in energy production costs which occur over one year. Capacity costs are typically assumed to be invariable in the shortrun. Thus, avoided costs using this method only credit the SPP for the energy cost savings to the utility over the contract period. No credit is attributed to the SPP for reducing the utility's capacity requirements.

The peaker approach suggests that the value to the utility should reflect both energy and capacity cost savings which accrue to the utility as a result of the availability of private developed power.

This method may be used to examine marginal costs over several years, and utilizes the estimated capacity costs of a new central generator to measure the value of reductions in the utility's peak capacity requirements. Combustion turbine costs are generally used because this type of generating unit is usually the least-cost method of expanding capacity on a dollars-per-kilowatt basis.

The system planning approach also considers both the energy and capacity benefits which a SPP may offer a utility. But this method determines the value of reductions in the utility's peak capacity requirements through a more detailed simulation of its capacity expansion planning and generating unit dispatch decisions. The system planning approach examines the influence of the SPP's operations on utility decisions and costs over an extended period of time (e.g. the utility's planning horizon for new baseload capacity additions). It also considers anticipated energy cost savings in the evaluation of new generating capacity alternatives.

The long-run differential revenue requirements approach is similar to the system planning approach in that it examines utility decision making and costs over several years. It differs from the system planning approach, however, in that it focuses on examining financial relationships rather than the engineering variables which are the primary focus of the system planning approach. The utility's revenue requirements are estimated with and without the availability of privately developed power. The difference is the measure of the value of the power to the utility. This comparison provides estimates of avoided costs which are based on explicit consideration of the rate-making process. It also attempts to simulate such factors as lead times for capital expenditures, regulatory treatments of cost for construction work in progress (CWIP) and funds used during construction, and the cost impacts of delayed revenue collections by the utility.

One additional method of determining buy back rates which are not based on avoided costs, involves the consideration of average embedded costs. Only Kansas makes use of this method.

Questions as to projected discount rates, fuel costs, inflation and electrical demand lend themselves by their nature, to disagreement between the utility and the small power producer. With the exception of California, Nevada, Texas, Maine, New Hampshire, New York and Vermont the state regulatory commissions have generally accepted the utilities figures for computing avoided costs.

A California rate hearing illustrates the disagreements that can result in the consideration of avoided costs. Pacific Gas & Electric submitted an application to the PUC to lower buyback rates due to the

opening of the Diablo Canyon nuclear generating facility. The utility argued that this facility would have a 90% capacity figure which would have resulted in a drop in short term buyback rates from 6.9 cents to 4.85 cents per kWh. The Independent Energy Producers (IEP), a state association of small power producers successfully argued that the capacity factor should be 55% based on other nuclear reactors operated by Pacific Gas & Electric. Their brief advocated a three year trial period, before adjustment of buyback rates, during which time the true capacity value for Diablo Canyon would be identified. Further, they pointed out that if Diablo Canyon was to be utilized at a 90% capacity level, cheaper hydro power would be spilled, resulting in a lowering of the utilities actual hydro power capacity with a resulting positive influence on buyback rates.

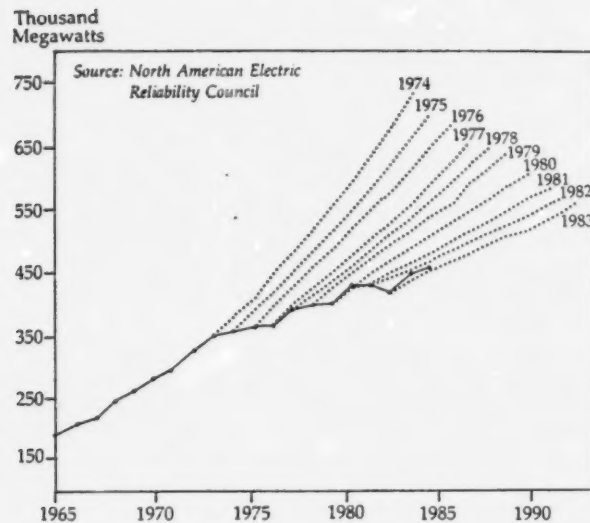
In another example of SPP influence, the New York state legislature has enacted a law that provides a floor price of six cents per kilowatt. This overpays or underpays SPPs depending on the utility concerned. The New York legislation was in response to Consolidated Edisons legal maneuvers.

Both the California and New York regulatory and legislative actions are a concern to utilities across the U.S.

A.3 Capital Considerations

The five-to-ten year lead times required to design and build a new mega-power plant, has forced utility planners to rely on long-range demand forecasts. Throughout the sixties and early seventies, most planners used a technique called trend line forecasting. Clark Gellings, a forecaster with the Electric Power Research Institute says, "in the sixties you plotted a few points on a piece of paper and trended them out, using simple regression technique to fit a curve. There seemed to be no limit to growth then."

The best example of this type of forecasting comes from the North American Electric Reliability Council, used by utility planners throughout the United States and Canada. For ten consecutive years between 1973 and 1983 the Council lowered its forecast, calling into question billions of dollars of investments that had been premised on the previous years predictions. In 1983, summer peak demand in the United States was 40% lower than projected a decade earlier. According to Public Utilities Fortnightly this equals the output from 300 large nuclear plants that would cost \$750 billion at 1983 prices.



Summer Peak Electric Demand, 1965-84,
And Projections Made from 1974 to 1983

About \$17 billion had been invested in planning and building the 53 U.S. nuclear plants cancelled since 1980. The market-price mechanism defined by PURPA and implemented by the state regulatory agencies encourages small power development in areas that need new capacity. The 18 MW average size of facilities constructed in 1984 and the twelve to eighteen month lead time needed for construction, means that new capacity addresses new demand in a more orderly fashion.

A study by the Investor Responsibility Research Center, who surveyed the 120 largest utilities in the United States in 1983 found that U.S. utilities will be cutting their construction requirements by at least \$45 billion over the next decade because of increased reliance on third party developed small generation facilities, conservation and load management. Small power alone is forecast by utility planners, to displace the need for 30,000 MW of electric capacity that utilities would have needed to develop in central generation facilities. Their report, Generating Energy Alternatives at America's Electric Utilities, focussed on utility planning strategies until the year 2000.

A.4 Contract, Non-Performance and Insurance Arrangements

Contract arrangements have satisfied utility fears concerning the technical and business reliability of SPPs. In each of the fifty U.S. states, contract clauses have detailed the requirements of both the SPP and utility. All utilities, with the exception of Con Ed who

does not yet have a standard contract, are satisfied with the protections the state regulatory agencies have given them. In general, contracts stipulate standards in the following areas:

- * location
- * obligations to provide service
- * conditions of delivery
- * character of service
- * rights and obligations of utility and customer
- * identification of the responsibilities of the owner, designer and operator
- * land rights
- * removal of equipment
- * safety
- * metering
- * type of measurement and error factors
- * liability
- * insurance
- * duration of contract
- * dispute resolution

The buyback rate is the key variable which determines whether or not the SPP and utility can come to an agreement. That portion of contract negotiations must be viewed as a chess game taking place at several levels. Other contract issues are largely settled.

A.5 Effect on Utility Power Generation Planning and Grid Management

From the perspective of the utility's financial stability, there are three items to consider when contemplating PURPA:

- * integration of a small power production strategy is a trade-off between technical risk and the flexibility of small scale incremental supply. Since technical risk and performance guarantees are assumed by the private developer, the advantage rests with the utility.
- * small power production facilities resemble nuclear and hydroelectric power in that they all substitute capital (fixed cost) for variable costs.

- * substitution immunizes the utility from the effects of substantial interest charges in the building of central generation facilities.

There are six major factors which collectively determine whether or not new electric generating plants are needed:

- * load growth - meeting increasing levels of electricity demand.
- * planning adjustments - adjusting actual generation to an average level.
- * reserve margins - keeping a sufficient number of plants in reserve in case others break down.
- * retirements - replacing older power plants with newer more efficient and reliable units.
- * contract expirations - termination of utility contracts for electricity.
- * fuel displacement - reducing consumption of expensive fuels or those which are susceptible to a supply disruption.

Tony Kilroy, of the Small Power and Cogeneration Planning Section, Pacific Gas & Electric, summarizes his utilities point of view:

From our viewpoint, there are attractive features to our participation with small power production developers. Chief among these are the possibilities (SPPs) provide for developing new supplies of electricity with shorter lead times, easier siting, increases in overall utility system efficiency and utilization of a broadly based number of resources. And of course (SPPs) provide new power that isn't financed by utility investment in new generating facilities."

The survey of U.S. utilities conducted by the Investor Responsibility Research Center titled Generating Alternatives at America's Electric Utilities, indicates that in 1982 utilities purchased 3,508 MW, from SPPs, that by 1992 the figure would total 12,547 MW, and that by 2000 small power producers would contribute at least 30,150 MW. The major utilities purchasing electricity from SPPs in 2000 will be Pacific Gas and Electric, with 4,920.5 MW; Southern California Edison, 2,693.5 MW; Houston Lighting and Power, 2,400 MW; Public Service Company of New Mexico, 1,512 MW; Virginia

Electric and Power, 933.7 MW; Gulf States Utilities, 600 MW; Tennessee Valley Authority, 540.8 MW; and Carolina Power and Light, 516 MW.

In terms of small power production as a percentage of fuel mix by the year 2000, the lead utility is expected to be PSC of New Mexico. They plan to obtain 59% of their total capacity from SPPs. Snohomish County Public Utility District in Everett, Washington will get 57.5% of its fuel mix from SPPs, or 86% of new additions. Sacramento Municipal Utility District is expecting 19.6%. Working from a much larger base, P.G. & E's additions will bring its percentage of SPPs to 18.2%.

U.S. electric utilities produced 2,240 billion kilowatthours in 1982 and had gross revenues of \$121 billion. According to Dr. Kirby Holte of Southern California Edison gross revenues could reach \$436 billion by 1994, assuming an annual growth rate in demand of 4% and rate increases of 7% per year:

Third party owned projects could capture a significant share of this market. A five percent market penetration in 1994 would result in 180 billion kilowatthours of sales and more than \$22 billion in revenues to small power producers. The incentive provided to third party developers and equipment manufacturers by this very large market potential is reason enough to attract major interest in renewable and cogeneration business ventures.

Privately developed small power generation has transferred the risk of new technologies out of the utilities' domain and has helped utilities develop smaller increments of capacity.

The long term fear of U.S. utilities is summarized by former Secretary of Energy, Don Hodel:

The electric utilities' view (is) that in the long term they'll simply become common carriers. This is an extremely serious concern to them because of what it may do to their investment programs in the future."

Each of the utilities surveyed felt there were existing inequities in the current law governing small power production in that it discriminates against utility involvement. Specifically, the limitations on utility ownership to 49% make them unable to benefit from the regulatory and tax benefits of small power development. They want to see this changed.

When PURPA was tabled in Congress in 1978, utilities expressed doubts about the effect of privately owned small power production on overall system reliability and safety. Concern was also expressed about the effect on the overall energy market share of electrical utilities, and the relationship between gas, oil and electricity in the marketplace. Those utilities with excess capacity also questioned how beneficial decentralized electrical generation would be in terms of the short-term economies of their systems. The utility lobby indicated in no uncertain terms that a new regulatory scheme to promote the development of private electrical generation was both unnecessary and harmful to their interests.

In 1985 however, utility planners are now integrating the privately developed small power production option in their planning strategies.

CHAPTER FIVE

SMALL POWER PRODUCERS

EXPERIENCE

WITH

PURPA

CHAPTER SUMMARY

- 1) Since 1980, applications have been filed for 785 small-scale power projects with a total generating capacity of 14,193 megawatts. The average power output of each plant is 18 MW. Cogeneration is the most important component, accounting for two-thirds of the total, but each year the mix of new sources becomes more diverse.
- 2) Cogeneration systems are more economical than virtually any other power source available. Installed costs range from \$500 to \$1000 per kilowatt, depending on the technology and fuel. Total generating costs are less than half those for nuclear or coal plants being built.
- 3) The California market is the most attractive at this point because of the political and regulatory environment, the natural resource base, availability of financing and the attitude of the people. When the California market is saturated, SPPs will start pursuing other markets.
- 4) SPPs must know in detail the way in which buy-back rates and terms and conditions with a utility are determined, and they must be able to provide credible arguments and analysis to support their position. They must be able to differentiate between ratepayer, utility and SPP interests and they must find ways to balance these interests.
- 5) The small power producers who are using renewable sources for electrical generation feel that the termination of federal and state credits will result in a "shakeout" and will discourage potential new companies from entering the field. But they are satisfied that their businesses have built a track record that will enable them to approach present investors with projects that offer a smaller rate of return. The element of risk has considerably diminished.
- 6) The U.S. grid system was built to distribute power from central generation facilities. As a result, the problem of inadequate transmission capacity is expected to become the predominant issue of decentralized electrical generation in the 1990s.



Introduction

In August, 1983, at the Renewable Energy Technologies Symposium U.S. Secretary of Energy Donald Hodel, gave the Reagan Administration's position on small scale electrical generation development :

It is going to be a big industry not only in the United States but I think in the whole free world. Billions of dollars are going to be spent and a contribution of a like size is going to be made to this nation. What you are doing is good for America, it's certainly good for the western world, and I hope will be good for your businesses ... your competitive position, indeed your future, is enhanced by the flexibility your technologies provide to an electric utility as far as determining when it needs to add resources and what those resources are to be."

A.1 SMALL POWER DEVELOPMENT: THE MARKETS

Small-scale power production using a variety of new energy sources is gaining market share far more rapidly than projected only a few years ago. Figures from FERC show that since 1980, applications have been filed for 785 small-scale power projects with a total generating capacity of 14,193 megawatts. The average power output of each plant is 18 MW, or less than 2 percent of the capacity of a standard nuclear plant. Cogeneration is the most important component, accounting for two-thirds of the total, but each year the mix of new sources becomes more diverse. Wind, small hydro and biomass projects are growing most rapidly.

Some SPPs have arisen solely for the purpose of selling all of the electrical output from their projects to utilities. All aspects of project development, implementation, and operations are handled under a single management framework. They must have the full range of capabilities to conceptualize, arrange financing, design, engineer, procure, and construct the electrical generation facilities. Their total business function is the sale of electricity to utilities. Developments, include:

- * In Churchill County, Nevada, Trans-Pacific Geothermal Inc., has developed a geothermal electric generation system. The facility contributes 24 MW of firm capacity to the grid. Trans-Pacific has developed twelve such facilities in the Northwestern United States over the past three years.

- * In Chatsworth, California, Arco Solar has built a 1 MW photovoltaic small power project. Seen as a demonstration of photovoltaics, Arco Solar is expecting to develop projects of an increasingly larger size over the next few years.
- * In Tehachapi, California, Zond Systems has operated a windfarm since 1981. Each year, rated capacity of the project increases as more wind turbines are added to the development. By December, 1984 the project has a rated capacity of 29.4 MW. In 1981 Zond Systems had four employees. By 1984, the company had expanded to employ 251.
- * In Armstrong County, Pennsylvania, Atlantic Power Development Corporation has built a 5 MW hydro facility. It is one of eight such developments by the company.
- * In Smithtown, New York, Pacific Lighting Energy Systems has constructed a 1 MW generator powered by methane gas from a municipal landfill site. Similiar projects are now being developed in Monterey and Onondaga, New York, East Windsor, Connecticut, and Santa Clara, California.
- * In Tuolumne County, California, Ultrasystems has built a 22 MW power generation project fueled by biomass wastes. Ultrasystems has built 14 such projects throughout the United States.

Other SPPs generate electricity as a secondary business function because it saves them money and provides a new source of revenue. Cogeneration has been the primary technology used in this type of development.

Cogeneration systems are more economical than virtually any other power source available. Installed costs range from \$500 to \$1,000 per kilowatt, depending on the technology and fuel. Total generating costs are less than half those for nuclear or coal plants being built.

Examples from the the Federal Energy Regulatory Commission indicate the range of businesses and institutions that have added electricity sales to their operations as a source of revenue:

- * In Bakersfield, California Superior Farming Company has installed a 5.7 MW cogeneration plant fueled by almond and fruit tree trimmings. The steam produced by burning these tree trimmings is first used to drive the turbine generator and then used in the company's dehydration plant. The facility displaces \$370,000 of natural gas previously used in the dehydration plant, while

producing \$1.5 million of electricity that is sold to the utility. In 1983 this project was cited by the Environmental Protection Agency as a good example of how an industry can reduce air pollution. The waste materials were formally burned in open pits.

- * In Mobile, Alabama, the Scott Paper Company has built turbine generators and biomass and waste heat recovery boilers to make itself 60 percent energy self-sufficient. Their remaining electricity needs are purchased from the utility. But for billing purposes, the on-site generation is considered as part of the total demand. This factor allows Scott Paper to obtain its supplementary power at the cheapest available price. As of February, 1985 the company has installed cogeneration equipment at one-third of its paper mills from Maine to Alabama.
- * In Oakland, California Kaiser Engineering developed, financed and operates a 25 MW natural gas cogeneration system for the City Center Building complex. Through sales to private businesses located in the complex, Kaiser Engineering is able to pay the city \$1 million per year in energy royalty payments.
- * In Freeport, Texas Dow Chemical Company has built a 1,300 MW cogeneration system. About 75% of the electricity is used on site with the remainder sold to the utility. The ten-year contract for 225 MW of firm capacity will provide income to Dow Chemical of \$1.3 billion.
- * In Bieber, California Big Valley Lumber Company, operates a 5 MW cogeneration plant fueled by forest slash and pulp waste. The company receives an additional \$1.3 million in income per year from electricity sales to the utility.
- * In West Babylon, New York, Ener Pak Inc. has constructed a waste fired cogeneration system for Mediwest, fueled by hospital garbage in the New York city region. The project has a 2 MW capacity and has been financed through a shared savings program. Service and maintenance costs will be deducted from the revenue received from the utility, Lilco, and the net profit will be subject to sharing. For the first seven years the income is being shared 80% by Ener Pak and 20% by Mediwest. For the next twenty one years, the share will be 60% Enerpak and 40% Mediwest.
- * In Sacramento, California Imotek operates an 8.5 MW cogeneration facility that is fueled entirely by almond hulls. The company purchases 82,000 tons per year of the hulls from the California Almond Growers Exchange in exchange for 125,000 lbs./hr of steam.

Excess steam is sold to a car parts manufacturing firm, while the power is sold to the utility.

- * In Oberlin, Ohio Oberlin College constructed a natural gas fueled cogeneration system to produce steam for heating campus buildings and electricity for sale to the municipal utility. The facility is providing 775 kW of firm capacity only during the early morning and late afternoon peak demand periods. Oberlin College is the sole owner.
- * In Anderson, California Simpson Paper Company, operates a 36 MW natural gas-fired cogeneration turbine. The plant is fully automatic and can operate at full load from a cold start in 18 minutes.
- * In Lassen County, California Union Oil has developed a geothermal cogeneration project that is owned by limited partners. The project provides 110 MW of firm power to PG & E while also selling steam to the state correctional facility located beside the project. The State is saving \$250,000 per year in heating costs as a result of this development.

B.1 CONCERNS OF SMALL POWER PRODUCERS

The viewpoint of small power producers in the United States is summarized in the following six points:

- * Ratepayers should be indifferent about whether power development is initiated by SPPs or utilities.
- * SPPs should be prepared to accept greater risks than utilities in exchange for the opportunity to earn greater returns.
- * Ratepayers should not expect SPPs to shoulder all risks of development but should accept a reasonable balance of risks and rewards.
- * Utilities should provide reasonable pricing certainty for SPPs and ratepayers over the longer term.

- * Public Utility Commissions should compute avoided costs to actively reflect the long term contribution of SPPs. e.g. technology development and grid expansion deferrals.
- * Government and the regulatory agents should encourage the development of cogeneration and renewable energy production facilities by insisting on long term contracts which are equitable for all parties.

Janice Hamrin, Executive Director of the Independent Energy Producers, a trade group representing the California small power industry, has followed the development of PURPA since it became law. Though the small power industry is highly competitive in the United States, says Hamrin, mutual interest in addressing common "macro-market" concerns has brought the industry together as a formidable force:

Legislation can either help or hinder an industry's development. When a new industry, like ours, becomes a focus of political interest, the only way to keep legislation positive is for the industry to form a visible presence and make some collective decisions as to what it needs and does not need.

Hamrin feels that the Independent Energy Producers Association has become a major force in the electrical generation industry. The massive development of small power production sites in California has indicated the important role such an organization plays:

I don't feel that (the association) can effectively represent small power producers nationally because so much of what PURPA is defined as is applied at the State level. There are several effective organizations who represent the interests of the renewable energy industry at the national level. But that is not enough.

Hamrin's views on new markets illustrates why California has been the core market of small power production:

The California market is the most attractive at this point because of the political and regulatory environment, the natural resource base, availability of financing and the people. It has utility decision makers who, while being tough bargainers have developed a knowledge base in the new electrical technologies ... When (the California) market is saturated we'll start pursuing other markets with a similar coalition.

B.2 Avoided Cost Issues

To be effective, the small power production industry has to be aware of the many issues surrounding the computation of avoided cost. The California experience illustrates that SPPs must have more than "the higher the better" attitude in negotiating buy-back rates and terms and conditions with a utility. SPPs must know in detail the way in which such computations are determined and be able to provide credible arguments and analysis to support their position. They must be able to differentiate between ratepayer interest, utility interests and SPP interests and they must find ways to balance these interests.

Accurate determination of avoided cost requires a concerted SPP effort within the state regulatory framework. "The way PURPA has been implemented in the states demands active participation by small power producers", says Jan Hamrin. "When there are hearings on avoided costs, the utilities work to protect their interests, and the Commissioners want to keep rates down. Poor preparation by SPP interests, and in some States the absence of SPP input, has lead to buyback rates that are not based on avoided costs."

The California example of the Diablo Canyon hearings is illustrative of the research SPPs must undertake in order to protect their interest. Further information on these hearings is found in the UTILITY chapter.

B.3 Contract Arrangements

As stated in CHAPTER FOUR, the major contract arrangements are no longer contentious. But there are some concerns about the "closed-contracts" that Public Utility Commissions have advocated.

Contingent liability provisions contained in many standard contracts present SPPs with three open-ended risks. Government jurisdiction liability can pose problems if, for example, new incentives are approved and the SPP is locked into a contract with less attractive conditions. SPPs want the right to renegotiate to take advantage of new terms. At the same time, the removal of legislation such as PURPA, could devastate a small producer's viability. The industry wants to have a guarantee written into their contract with a utility that even with legislative change, their status would be protected.

A second contingent liability in standard contracts is the requirement for a small power producer to pay for any future changes in the utility's grid that might be necessitated by interconnection.

Finally, many standard contracts contain a provision allowing the utility to curtail its purchases of power if cheaper power is available somewhere else.

Other than these three general concerns, which Hamrin stressed, "are not at the top of the pile", SPPs are generally pleased with the present contract terms and conditions. "(The contract) issue is resolved", says Bob Gates. "Our differences with the utility are confined to negotiating buyback rates and capacity credits. With a little more work, those issues will also be resolved."

B.4 Tax Policy

"In 1981 when we approached investors", says Bob Gates of wind farm developer Zond Systems, "they said wind-what? In 1985, they know what we're talking about. Our first investors are coming back, they know what we're all about, and they're buying into our new developments." Gates feels that the renewable energy tax credits expiry will inhibit some development. But existing investors, who he claims have been pleased with their rate of return, will continue to buy into their developments. This view was echoed by David Halbert of Lajet Energy Systems and Patricia Fuchs of Fayette Manufacturing. Says Fuchs, "we believe we have a stand-alone, viable investment with or without the credits."

The small power producers who are using renewable sources for electrical generation feel that the termination of federal and state credits will result in a "shakeout" and will discourage potential new companies from entering the field. But they are satisfied that their businesses have built a track record that will enable them to approach present investors with projects that offer a smaller rate of return. The element of risk has considerably diminished.

SPPs are more concerned about proposed changes in the tax code which would eliminate the standard 10% investment tax credit and the five-year accelerated cost recovery system. The proposal would also lower general tax rates, making third party investments less valuable. If these changes are made in concert with the termination of renewable energy tax credits, most small power production projects would not be viable.

B.5 Impact on Grid Development

The surge of interconnection activity in California created a situation that will be faced throughout the U.S. as SPP development expands. Pacific Gas & Electric identified two-thirds of its service

area as having inadequate transmission facilities to handle the burden of interconnection. The Independent Energy Producers (IEP) estimated that 1100 megawatts of power which could be developed was at stake. Upgrading the utility transmission system, an option which carried a cost of as much as \$270 million, was the solution preferred by PG&E, IEP, and CalPUC. But there was no agreement on who should pay.

CalPUC ordered an interim settlement in July, 1984, whereby SPPs agreed to pay an assessment fee to keep ratepayers from suffering economic loss, while PG & E agreed to interconnect with small power producers in the affected area. The actual amount that SPPs must pay will be determined by a CalPUC ruling in the transmission case expected by July, 1986. Until then, small power production facilities in the affected area are assessed 1.7 mills per kWh, all but 0.5 mills of which may be refunded, pending the final ruling. CalPUC may also cancel the 0.5 mill access charge.

The U.S. grid system was built to distribute power from central generation facilities. As a result, the problem of inadequate transmission capacity is expected to become the predominant issue of decentralized electrical generation in the 1990s.

B.6 Wheeling

As the independent electrical generation market expands, "wheeling" power to utilities with relatively higher buyback rates is essential for the continued strong growth of the SPP industry.

The SPP industry sees litigation as the only avenue available to force utilities to wheel power produced by independent generators. (See sections D.1, E.1 and E.2 in CHAPTER TWO)

C.1 CONCLUSION

Small power producers are bullish on the unfolding market potential. PURPA and progressive tax measures have opened up a significant market area that has furthered the U.S. effort at diversifying its energy supply base.

CHAPTER SIX

CANADA
AND
SMALL POWER
PRODUCTION

CHAPTER SUMMARY

- 1) While there are significant differences between U.S. and Canadian utilities, we believe that the principle benefit of PURPA, i.e., introducing competition into the market for power generation, is appropriate for Canada.
- 2) An appropriate policy environment has not been put in place in Canada to stimulate development from alternative supply sources simply because neither the responsible provincial agencies or the utilities have recognized the need or perceived any opportunity or advantage in taking any action.
- 3) Rates offered by Canadian utilities for privately generated electricity do not approach retail rates.
- 4) All Canadian utilities will permit the interconnection of customer owned generation. But 33% of surveyed utilities have not arrived at set terms and conditions for inter-connection.
- 5) 67% of Canadian utilities will purchase surplus energy from SPPs. The remainder allow a customer's meter to run backwards up to the point of electricity sold, but they will not give credit for any excess.
- 6) SPPs cannot accurately judge the basis for Canadian utilities' computations of avoided cost since the information is not presented in a public forum.
- 7) Canadian utilities are becoming increasingly aware of the potential and interest in small power production opportunities, but still do not regard these opportunities as important considerations in their overall generation plans.
- 8) The federal government has no jurisdictional authority to exercise on the power purchase policy issue with perhaps two exceptions - the Northern Canada Power Commission, and federal departments and agencies which maintain power supply facilities on their own account.
- 9) The maximum use of small power options in Canada will only be achieved by active utility participation in the development of small generation projects. For this reason we feel the small power production dialogue should be seriously pursued among SPP's, utilities, financial and legal institutions, and provincial and federal government agencies. We do not feel legislation is necessary, at least for the moment.

A.1 INTRODUCTION

This chapter is intended to set the parameters for a more structured dialogue concerning the consideration of small scale electrical production in Canada. It is not intended to be a blueprint for a plan of action, but rather to indicate that there appears to be a growing need to consider the role of small scale power development in a more comprehensive fashion. While there are significant differences between U.S. and Canadian utilities, we believe that the principle benefit of PURPA, i.e., introducing competition into the market for power generation, is appropriate for Canada.

U.S. experience has shown that SPPs were able to sell more easily to those utilities generating electricity with nuclear and fossil fuels than those generating electricity largely by hydro. This is due largely to cost differences among these technologies as well as regulatory and environmental requirements.

Further, the U.S. experience indicates the importance of a coordinated SPP industry lobby effort in order to achieve buyback rates based on actual avoided costs. Naturally, the first stage of development in the United States concentrated on the most advantageous markets, i.e. those utilities with a need for new power or those using expensive fuel sources in states with a varied renewable energy resource base and cogeneration potential, as well as a regulatory framework which encouraged independent generation.

The most important long-term benefit of PURPA was the establishment of an accurate pricing mechanism for various electrical generation options. Such pricing has contributed to the reduction of overall energy market distortions. In the area of cogeneration in particular, attractive avoided cost buyback rates lead to greater consideration of commercial and industrial energy efficiency, and thus greater productivity and competitiveness in industrial and commercial market sectors.

As previous chapters have shown, the utility business in the United States has gone through a tremendous adjustment period in the past few years. Canada's public utilities on the other hand, while experiencing some of the difficulties encountered by their U.S. counterparts, have responded to these problems in different ways. Projects have proceeded to completion despite cost increases and slackening demand.

In response, Canadian utilities have increased their debt loads, moderately increased rates, and aggressively pursued domestic and export marketing of surplus power. At present, several utilities remain with a significant surplus supply capability and a debt load which is beginning to place a burden on their provincial government. Future generation plans have been deferred or postponed, and alternative electricity generation technologies in the small power realm have not been pursued. An appropriate policy environment has not been put in place to in Canada stimulate development from these alternative supply sources simply because neither the responsible provincial agencies or the utilities have recognized the need or perceived any opportunity or advantage in taking any action.

Most Canadian utilities have established power purchase policies, but rates offered to independent power producers are not debated and established in a public forum. In several jurisdiction, due to existing surplus supply, rates offered are based on avoided fuel costs only (e.g. from coal or oil-fired plants), without allowance for capital costs. In other provinces, utilities will accept but not pay for surplus power generated, while a few Canadian utilities have established policies of net billing at retail rates, some with, and others without, payment based on avoided fuel costs for any surplus power supplied to the grid system.

Unfortunately, unlike in the U.S., rates offered by Canadian utilities for privately generated electricity do not approach retail rates, and individuals and companies with an interest in small power production believe these rates are significantly below what would otherwise be the utility's true avoided cost.

Several studies undertaken in recent years have shown there is some potential for various small power technologies in stand-alone, grid-connected and remote community applications across Canada. For example, a study by Techno-Economic Research Unit has compiled an inventory of approximately 350 MW of remote site diesel generated electricity capacity, and has identified a renewable resource base capable of displacing some of this expensive diesel power. Yet, to date, small power producers have been unable to seriously address this market due to information and institutional constraints. Recently, EMR's Remote Community Demonstration Program (RCDP) has encouraged more serious investigation of this potential.

Canadian small power producers are poised to enter the electricity supply market in Canada. In terms of utility policy, these companies are much further ahead than their U.S. counterparts were in 1978. Until PURPA, U.S. SPPs were unable to interconnect with U.S. utilities. The major issue to be confronted in Canada is thus not interconnection, but fair buyback pricing. In our view, this issue need not necessarily be dealt with at the legislative level.

In this chapter, we examine the Canadian situation.

B.1 CANADIAN UTILITY POWER PURCHASING ARRANGEMENTS

The following information is drawn from a Canadian Electrical Association (CEA) study, Electric Utility Policy on Interconnection with Small Power Producers and supplementary interviews with utility representatives.

B.2 Right to Interconnection

All Canadian utilities will permit the interconnection of customer owned generation. But 33% of surveyed utilities have not arrived at set terms and conditions for interconnection.

Generally, the terms and conditions for interconnection for those utilities that have a defined policy can be summarized by the following ten points:

- 1) Interconnection must not cause a reduction in the quality of service to other customers. If it does, the equipment will be disconnected until the problem is resolved.
- 2) Interconnection may not commence until written approval is received from the utility.
- 3) The customer wishing to interconnect shall indemnify and hold the utility harmless should damages result from the operation of the SPP system. These customers must carry liability insurance.
- 4) The generating equipment cannot energize or de-energize the utilities circuit.
- 5) The generator must not adversely affect utility voltage regulation.
- 6) The equipment shall not cause adverse harmonics to the utility's system.
- 7) The equipment must be kept in good working order.
- 8) In emergency situations, the customer shall discontinue parallel generation when requested by the utility.
- 9) Customers shall maintain an operating log.
- 10) Customers must notify the utility in writing of its monthly kWh production.

B.3 Canadian Purchase Rates

The CEA report indicates that 67% of Canadian utilities will purchase surplus energy from SPPs. The remainder follow the example of Saskatchewan Power Corporation which allows a customer's meter to run backwards up to the point of electricity sold, but they will not give credit for any excess.

While in the United States, power purchases are based on the full avoided capacity and fuel costs of a utility's newest central generation facilities, Canadian utilities base buy-back rates on a variety of formulas including: trailing step; 70% of replacement fuel; time differentiated average cost of generation; wholesale rates less administration costs; allowing the meter to run backwards; avoided fuel costs.

All of these result in much lower rates being offered to SPPs. As well, unlike in the U.S., Canadian SPPs do not have the additional advantage of selling all of the power they generate at full avoided cost, while purchasing their own power needs at retail rates.

Unfortunately SPPs cannot accurately judge the basis for Canadian utilities' computations of avoided cost since the information is not presented in a public forum. While most provinces do conduct hearings concerning utility rate schedules, little time, if any, is spent on the consideration of generation alternatives and the price that should be paid for privately generated electricity. In the U.S. retail rates and avoided cost are handled in separate hearings, in order to give the detailed attention required to each function. This is not done anywhere in Canada. For example, when Ontario Hydro recently raised the fuel portion of their buy-back rates on December 13, 1984, the following rationale was used:

In the past, rates paid for parallel generation were based on Hydro's average cost of generation. The new rates take into account projected future costs as well as current costs.

No further information was made available to existing or potential small power producer's.

The following list summarizes the power purchase policies of Canadian utilities:

BRITISH COLUMBIA

B.C. Hydro & Power Authority	Main Grid	Will accept but not pay for power due to main grid generating surplus.
	Remote Grids	Individually negotiated at 75% of displaced fuel cost starting at 7 cents per kWh.

ALBERTA

Alberta Power	Main Grid	Net billing at retail rate. Average 5 cents per kWh for residential customers.
Northern Canada Power Commission	Most Grids	Will accept but not pay for surplus power generated.
TransAlta Utilities	Main Grid	Net billing at retail rate. Surplus computed quarterly and paid based on the avoided coal fuel cost, 1.6 cents per kWh.

YUKON TERRITORY

Northern Canada Power Commission	Most Grids	Will accept but not pay for surplus power generated.
Yukon Electric Co.	Main Grid	Net billing at retail rate.

NORTHWEST TERRITORIES

Northern Canada Power Commission	Most Grids	Will accept but not pay for surplus power generated.
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SASKATCHEWAN

Saskatchewan
Power Corp.

Main Grid

Will accept power
generated from systems up
to 15 kW with net billing
at retail rate. Policy
may be reviewed and
altered in 1987.

MANITOBA

Manitoba Hydro

Main Grid

Hook up permitted, but
policy to be established
by 1985.

Remote Grid

Purchases power at full
cost of \$0.087/kWh.
Transmission line to main
grid may be built in 1987

ONTARIO

Ontario Hydro

Main Grid

Will pay hybrid avoided
average fuel cost, as
well as accounting for
future generation costs.
Base rate of 3.3 cents
per kWh will be paid for
power generators with
monthly capacity factors
over 65%. Base rate of
2.3 cents per kWh for all
others, except
cogeneration at 1.95
cents per kWh.

Remote Grids

Same hybrid rates.

QUEBEC

Hydro Quebec

Main Grid

No Policy.

Remote Grids

No Policy.

NEWFOUNDLAND

Newfoundland and Labrador Hydro	Main Grid	Will permit hook up. Buy-back rates determined on a case by case basis.
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NEW BRUNSWICK

New Brunswick Power Commission	Main Grid	Power bought at industrial runoff rate at \$0.021/kWh.
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Saint John Power Commission	Main Grid	Net billing at industrial service class, \$0.033/kWh.
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NOVA SCOTIA

Nova Scotia Power Corp.	Main Grid	Net billing for systems up to 10 kW capacity. 70% of avoided fuel costs for systems up to 15 MW capacity. Systems above 15 MW must be negotiated directly with the utility.
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PRINCE EDWARD ISLAND

Maritime Electric Commission	Main Grid	Will purchase surplus power at \$0.055/kWh. PEI PUC held hearings in the fall of 1984 and new rates are expected to be announced shortly.
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B.4 RECENT TRENDS

The above information reflects utility power purchase policies of March, 1985. The recent rate adjustment announced by Ontario Hydro is included. A decision on P.E.I. power purchase rate changes has still not been made.

These data mask recent developments in utility approaches to the power purchase issue which serve to illustrate the present context. Several utilities have moved to allow interconnection in the last few years, while the action of others have led to government or regulatory authority responses. For example, the Northern Canada Power Commission (NCPC) issued terms and conditions for the interconnection of wind electric generators in September, 1983. But it announced it would only allow wind turbines up to 10 kW to interconnect and that it would not offer anything for surplus power generated. The situation remains this way to date, and NCPC has not offered a policy rationale that is acceptable to small power producer interests.

A more dramatic illustration of recent developments took place in February, 1984 when the Saskatchewan Power Corporation (SPC) refused to offer favourable rates or to consider a proposed 50 MW biomass facility in their generation plans for Northern Saskatchewan. One involved individual, Ben Baich, embarked on a five-day hunger strike on the steps of the provincial legislature. The issue was resolved when SPC offered to negotiate a formal power purchase agreement, but the project has not proceeded due to financing difficulties.

A third example occurred in Alberta during late 1983 and 1984 when an Alberta farmer, Mr. A.E. Sinnott, could not establish acceptable terms and conditions for power purchase with TransAlta Utilities. A hearing was requested with the Alberta Energy Resources Conservation Board (AERCB), and on June 12, 1984 the AERCB issued a landmark decision.

The Board ruled that Sinnott should be allowed to "bank" electricity generated from his windmill in the TransAlta grid, "and draw on that credit by taking energy from the TransAlta system during periods of low or zero wind." Sinnott successfully argued that it "wasn't fair" for TransAlta to bill him 5.2 cents per kWh for electricity supplied when the wind regime wasn't adequate, while only offering to pay 1.6 cents per kWh for surplus electricity.

The AERCB decision requires TransAlta to bill Sinnott at the normal 5.2 cent rate only if it supplies him with power beyond what he produces and banks every three months. Under the TransAlta proposal Sinnott would have only been credited 1.6 cents per kWh for all electricity he fed into the grid. The AERCB decision to consider the value of energy on a quarterly rather than immediate basis, raised the effective buyback rate for Sinnott's total demand 300% above the TransAlta offer. Any surplus is credited at the 1.6 cents per kWh rate. A copy of the AERCB ruling is attached as APPENDIX D.

A final example is a recent situation which has arisen in Nova Scotia regarding power purchase from a 225 kW small hydro facility at Melford Brook. Prior to construction, the Nova Scotia Power Corporation policy of payment at 70% of avoided fuel costs led the developer to expect a rate of 3.6 cents per kWh for surplus power generated at the facility. However, the first few payments have been in the 2-2.5 cents per kWh range. This was a disappointing surprise to the project developer whose contract did not protect him from the drop in fuel costs which recently took place in the province.

The above examples indicate that developments are beginning to take place in Canada on the power purchase issue. Canadian utilities are becoming increasingly aware of the potential and interest in small power production opportunities, but still do not regard these opportunities as important considerations in their overall generation plans.

On the other hand, small power producers see their companies' marketing plans hindered by utility power purchase policy because planned projects are not able to generate adequate cashflow to rationalize the required investment. Without an appropriate public forum for discussing and establishing power purchase rate policy, small power producers are left in the position of having to accept whatever the utility decides to offer.

C.1 FUTURE POLICY DIRECTION

The Public Utility Regulatory Policies Act (PURPA) in the United States is a piece of federal legislation with regulations administered by the Federal Energy Regulatory Commission (FERC). By contrast, within the Canadian political system, each Canadian province has jurisdictional responsibility for natural resource management, including electricity supply development. In turn, most Provincial Legislatures (except for Alberta and P.E.I.) have assigned responsibility for power development to Crown Corporations established through facilitating legislation. These utilities have a mandated monopoly to supply and distribute electricity to consumers at the lowest possible cost. They are exempt from paying property taxes and provincial and federal income taxes, and they have the additional advantage of access to capital at preferred rates due to provincial government guarantees on their debt funding requirements.

The federal government thus has no jurisdictional authority to exercise on the power purchase policy issue with perhaps two exceptions. First, the Northern Canada Power Commission (NCPC), a federal crown corporation, has a federally legislated mandate to supply electricity to communities in the Yukon and Northwest Territories. It is possible that steps could be taken to encourage NCPC to establish a fairer and more reasonable policy towards the purchase of electricity from SPPs. But action with regard to NCPC would have to await the outcome of devolution or sale discussions now underway. Second, some policy initiatives could be taken by federal departments and agencies who maintain power supply facilities on their own account, including service to communities located on federally owned land such as National Parks.

Outside these exceptions, any specific action on the power purchase issue rests within provincial responsibility. But because Canadian utilities are willing to interconnect (a situation which did not exist in the U.S. in 1978) and because we want Canadian utilities to work in conjunction with Canadian small power producers, we do not feel that PURPA-type legislation is a route Provincial governments need to contemplate, at least for the moment.

While PURPA opened a substantial market for SPPs in the United States, implementation continues to be contentious. The advocacy framework created by PURPA continues to perpetuate differences between utilities and SPPs, preventing direct utility involvement in small power production. The maximum use of small power options in Canada will only be achieved by active utility participation in the development of small generation projects.

For this reason we feel the small power production dialogue should be seriously pursued through communication and discussion among SPP's, utilities, financial and legal institutions, and provincial and federal government agencies. We do not feel legislation is necessary, at least for the moment.

If such discussion is to take place, however, it has been our experience that its initiation is going to have to come from the provincial government level. Provincial utilities are unlikely to take a proactive role in this regard. The federal role (other than potentially setting an example through the two exceptions mentioned above) will be to act as a facilitator. Information such as that included in this report, meetings, seminars and perhaps the sponsorship of conferences which address this topic are all essential at this time.

Provincial government agencies and utilities will be left in the primary role of undertaking further action with regard to power purchase policy. As this report suggests, one of the first steps should be to investigate whether a more public forum could be established for the determination and adjustment of power purchase rates. We believe this initial step is a prerequisite for the realization of the identified small power production potential in Canada.

**CONCLUSIONS
AND
RECOMMENDATIONS**

CONCLUSIONS

This study has closely examined the Public Utility Regulatory Policies Act (PURPA) which was legislated in the U.S. in 1978 as part of a comprehensive national energy strategy for the 1980's, and has attempted to relate the experience of PURPA to the Canadian situation. It is the primary conclusion of this report that though PURPA has had a degree of success, similar provincial legislation in Canada is not appropriate at this time.

We recognize the difficulty in computing avoided costs, especially in situations of surplus capacity. However, since small power production is a new business development area with numerous risk factors associated with the market development of new technology, and since avoided costs reflect the utilities' actual costs for new generation facilities, buy-back rates based on utility avoided cost are essential.

Provincial limitations on the degree of market penetration of SPPs would be highly theoretical and are therefore unnecessary at this time.

RECOMMENDATIONS

- 1) Avoided costs should include both fuel and capital considerations as is the practice in the United States.
- 2) In order to accurately assess avoided costs, utilities should disclose the following data on a yearly basis:
 - a) Main grid - a computation of the actual cost per kWh, including capital and fuel costs, for the most recently constructed central generation facilities.
 - b) Main grid - the utility's plan for the addition of capacity by amount and type, and for capacity retirements for each year during the succeeding ten years. This would then allow for accurate computation of the estimated capacity costs, at completion, of the planned capacity additions.
 - c) Remote grids - the utility's actual generation costs.

From this computation, long-term contracts that would take into account future increases in the utility's avoided cost, should be offered to SPPs.

If a utility operates remote grids, a separate buy-back rate based on the actual costs of the specific remote grid should be offered to SPPs.

- 3) Where the federal government has the authority, i.e. the Northern Canada Power Commission, and given EMR's Remote Community Demonstration Program, EMR should meet with the Department of Indian Affairs and Northern Development to encourage the development of buyback rates appropriate to the avoided cost of electricity within this utility's jurisdiction.
- 4) The regulatory process affecting SPPs should be streamlined. Standard offers and technical requirements should be offered in each province and territory.
- 5) Governments at all levels should work to eliminate financial as well as institutional constraints that inhibit SPP development.
- 6) An investigation should be conducted into the various rules and regulations affecting Canadian electrical utility operations in order to identify areas for SPP exemption. i.e. The definition of assets which qualify for investment tax credits 127(10) is tied to the definition of assets which qualify for the manufacturing and processing tax credits 127(11). This section specifies that manufacturing and processing includes activities described in 125.1(3)(6)(i) to (ix). Among the activities excluded are:

"125.1 (3)(b)(viii) the production or processing of electrical energy or steam for sale".

This exclusion puts many projects involving the recovery or use of alternate energy sources at a disadvantage relative to other processing activities. The Department of Finance should therefore consider the elimination of this exclusion for SPP development.

- 7) The federal government should encourage the organization of a workshop (perhaps under the auspices of the Canadian Electrical Association) where utility and SPP representatives could discuss mutual concerns including contract terms and conditions, methodology for determining buyback rates and the reliability of small power production technology.
- 8) Further use of EMR demonstration funds, as well as the Remote Community Demonstration program, should be used to encourage the demonstration of various SPP options. EMR should consider the development of a demonstration strategy specific to SPPs.
- 9) The federal government should insist on detailed monitoring of demonstration projects in order to better answer a general utility concern about the reliability of these new technologies. Monitoring would also determine appropriate capacity factors.

- 10) Utilities should, as required in the U.S., advertise and promote the possibility of interconnection to rural, industrial and commercial customers.
- 11) Provincial governments should instruct utilities to encourage the simultaneous sale and purchase of power.
- 12) Provincial governments should instruct utilities to encourage SPPs to enter into contracts with other SPPs in the same utility area to gain higher capacity factors through a better coordination of maintenance and mutual backup service.
- 13) If there is continued resistance to small power development in Canada, governments at all levels should consider the development of legislation, similiar to PURPA, at the provincial level.

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APPENDIX "A"



Information Required in Application
for Certification of Qualifying Status
(Checked box indicates deficiency, as noted)

Docket No. QF

1. (a) Name and address of applicant []
(b) Location of facility []
2. (a) Brief description of facility (Type of prime mover, whether []
small power production or cogeneration facility, narrative
sufficient to identify any unique characteristics of
facility.)
3. Primary energy source to be used by facility []
4. Power production capacity of facility []
5. Percentage of ownership by any electric utility or electric []
utility holding company
6. Federal Register Notice []
7. For small power production facilities:
 - (a) Whether facility is within one mile of other small power []
production facilities owned by applicant which use the
same energy source.
 - (b) Planned annual usage of natural gas, coal or oil: []
percentage of total energy input to the facility for each.
8. For cogeneration facilities:
 - (a) A description of the cogeneration system, whether a topping []
or bottoming cycle, and sufficient information to determine
that applicable requirements of 292.205 are met. (Cycle
diagram, gas and oil energy input, electric output, useful
heat output, description of useful heating purpose served,
computations for operating standard and for efficiency
standard.)
 - (b) Date installation of the facility began or will begin. []

§ 292.204

Title 18—Conservation of Power, Water Resource.

under Title II of the NCPA and Part 202 of the Commission's rules to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production.

(3) Nothing in this subpart affects any exemption provided under Subpart E of this part.

(4) Natural gas used for supplementary firing in any cogeneration facility is not eligible under this part for exemption from incremental pricing.

(d) Waiver. The Commission may waive any of the requirements of paragraphs (a), (b) and (c) of this section upon a showing that the facility will produce significant energy savings.

§ 292.206 (Ownership criteria).

(a) General rule. A cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities) or small power production facilities.

(b) Ownership test. For purposes of this section, a cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power, if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or electric utility holding company has an ownership interest in a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or electric utility holding company.

(c) Exceptions. For purposes of this section a company shall not be considered to be an "electric utility" company if it:

- (1) Is a subsidiary of an electric utility holding company which is exempt by rule or order adopted or issued pursuant to section 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 780(a)(3), 780(a)(5); or
- (2) Is declared not to be an electric utility company by rule or order of the

Securities and Exchange Commission pursuant to section 2(a)(3)(A) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 780(a)(3)(A).

(45 FR 17972, Mar. 20, 1980, as amended by Order 70-B, 45 FR 52780, Aug. 8, 1980; Order 70-D, 45 FR 11253, Feb. 6, 1981)

§ 292.207 Procedures for obtaining qualifying status.

(a) Qualification. (1) A small power production facility or cogeneration facility which meets the criteria for a qualification set forth in § 292.203 is a qualifying facility.

(2) The owner or operator of any facility qualifying under this paragraph shall furnish notice to the Commission providing the information set forth in paragraphs (b)(2) (i) through (iv) of this section.

(b) Optional procedure—(1) Application for Commission certification. Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) General contents of application. The application shall contain the following information:

- (i) The name and address of the applicant and location of the facility;
- (ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility;
- (iii) The primary energy source used or to be used by the facility;
- (iv) The power production capacity of the facility; and
- (v) The percentage of ownership by any electric utility or by any electric utility holding company, or by any person owned by either.

(3) Additional application requirements for small power production facilities. An application by a small power producer for Commission certification shall contain the following additional information:

- (i) The location of the facility in relation to any other small power production facilities located within one mile of the facility, owned by the ap-

Chapter I—Federal Energy Regulatory Commission

§ 292.207

applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) Additional application requirements for cogeneration facilities. An application by a cogenerator for Commission certification shall contain the following additional information:

- (i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under § 292.205 will be met; and
- (ii) The date installation of the facility began or will begin.

(5) Commission action. Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

(6) Notice. (i) Applications for certification filed under this paragraph shall include a copy of a notice of the request for certification for publication in the Federal Register. The notice shall state the applicant's name, the date of the application, and a brief description of the facility for which qualification is sought. This description shall include:

- (A) A statement indicating whether such facility is a small power production facility or a cogeneration facility;
 - (B) The primary energy source used or to be used by the facility;
 - (C) The power production capacity of the facility; and
 - (D) The location of the facility.
- (ii) The notice shall be in the following form:

(Name of Applicant)
Docket No. QP-
Notice of Application for Commission Certification or Qualifying Status of a Facility
(Small Power Production) (Cogeneration)

On (date application was filed), (name and address of applicant) filed with the Federal

Order 70-A, 45 FR 32603, May 20, 1980; Order 70-B, 45 FR 52780, Aug. 8, 1980)

Energy Regulatory Commission an application to be certified as a qualifying (small power production) (cogeneration) facility pursuant to § 292.207 of the Commission's rules.

(Brief description of the facility).

Any person desiring to be heard or objecting to the granting of qualifying status should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with 11.8 and 1.16 of the Commission's Rules of Practice and Procedure. All such petitions or protests must be filed within 30 days after the date of publication of this notice and must be served on the applicant. Petitions will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

(c) Notice requirements for facilities of 500 kW or more. An electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kW or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b) of this section.

(d) Revocation of qualifying status.

(1) The Commission may revoke the qualifying status of a qualifying facility which has been certified under this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

(45 FR 17972, Mar. 20, 1980, as amended by Order 70-A, 45 FR 32603, May 20, 1980; Order 70-B, 45 FR 52780, Aug. 8, 1980)

THE INDUSTRIAL COGENERATION MANUAL



C. A. Gaudin
Plant Manager

August 15, 1983

FILED
OFFICE OF THE SECRETARY
1983 AUG 19 AM 11:12

Amoco Chemicals Corporation

Post Office Box 568
Texas City, Texas 77590

FEDERAL ENERGY
REGULATORY COMMISSION

GF83-397-00

Certified Mail No. P11 1793196

Mr. Kenneth F. Plumb, Secretary
Federal Energy Regulatory Commission
825 North Capital Street
Washington, D.C. 20426

DO NOT REMOVE
FROM OPI

Dear Mr. Plumb:

This letter serves notice to the Federal Energy Regulatory Commission that Amoco Chemicals Corporation in Texas City, Texas qualifies as a cogeneration facility in accordance with the Public Utilities Regulatory Policies Act of 1978. The following is being submitted as requested in procedures for obtaining Commission certification in Section 292.207 Paragraph (b) of the Federal Register dated March 28, 1980:

- (2)(i) Amoco Chemicals Corporation
2800 Farm Road 519 East
P. O. Box 568
Texas City, Texas 77590
- (2)(ii) The Texas City cogeneration facility is a natural gas-fired combustion turbine with an ISO rated capacity of 37.1 MW. The facility is designed to burn distillate oil as an alternate fuel. A heat recovery steam generator designed for supplementary firing will produce 161,000 lbs/hr of 400 psig superheated steam unfired and up to a maximum of 325,000 lbs/hr of 400 psig superheated steam with supplementary firing. A portion of the electric power will be sold to Texas-New Mexico Power Company. The steam will be used for thermal energy in the processing units at the Amoco Chemicals Texas City plant.
- (2)(iii) The primary source of fuel for the facility is natural gas with distillate oil as an alternate fuel.
- (2)(iv) - The cogeneration facility has an ISO rated power production capacity of 37.1 MW.
- (2)(v) Amoco Chemicals Corporation, the sole owner of these facilities, is not an electric utility or public utility holding company.

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Sample Filings
10/1/83

THE INDUSTRIAL COGENERATION MANUAL

Mr. Kenneth F. Plush
Page 2

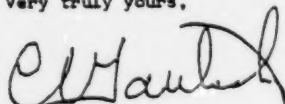
- (4)(i) The Texas City cogeneration facility is a natural gas-fired combustion turbine topping cycle. The applicable requirements under Section 292.205 Paragraph (a) of the Federal Register dated March 28, 1980 are met by this cogeneration facility. The Operating Standard at ISO rated conditions is 58.6% which is greater than the required standard of 5% as specified by Section 292.205 (a)(1). The efficiency standard at ISO rated conditions and at a fuel heating value of 970 BTU/SCF is 53.2% which is greater than the required standard of 42.5% as specified in Section 292.205 (a)(2)(i)(A)&(B).
- (4)(ii) The installation of the facility will begin approximately in October, 1984.

By way of this letter we are also requesting exemption from the incremental natural gas pricing contained in Title II of the Natural Gas Policy Act of 1978 and Part 282 of Commission rules for our topping cycle cogeneration facility since it meets the requirements outlined in Section 292.205 (c)(1)(i) of the subject dated Federal Register.

It is our understanding that this information fulfills the notification and application requirements of the Regulation for Commission certification. In addition, our understanding is that within 90 days of filing, the Commission will issue an order granting or denying this application. If no order is issued within the 90 days of the filing of the application, we understand that it shall be deemed to have been granted. Attached is a copy of a notice of our request for certification for publication in the Federal Register as required by Section 292.207 (b)(6)(i and ii) of the subject dated Federal Register.

If you require further information, please call Mr. T. G. Soles at (409) 948-1601, extension 229. However, any written correspondence should be directed to me.

Very truly yours,



C. A. Gautschy
Plant Manager

FHS/a

Attachment

DO NOT REMOVE
FROM OFI

A-55b
Sample Filings
10/1/83

A-4

THE INDUSTRIAL COGENERATION MANUAL

Amoco Chemicals Corporation
Docket No. QF-

NOTICE OF APPLICATION FOR COMMISSION CERTIFICATION OF QUALIFYING STATUS OF A COGENERATION FACILITY

On August 15, 1983, Amoco Chemicals Corporation, 2800 Farm Road 519 East, Texas City, Texas 77590, filed with the Federal Energy Regulatory Commission an application to be certified as a qualifying cogeneration facility pursuant to 292.207 of the Commission's Rules.

The Texas City cogeneration facility is a natural-gas-fired combustion turbine topping cycle. The rated capacity of the cogeneration facility is 37.1 MW of electrical power. The facility is designed to burn distillate oil as an alternate fuel. A heat recovery steam generator designed for supplementary firing will produce 161,000 lbs/hr of 400 psig superheated steam unfired and up to a maximum of 325,000 lbs/hr of 400 psig superheated steam with supplementary firing. The steam will be used for thermal energy in the chemical processing units.

Any person desiring to be heard or objecting to the granting of qualifying status should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§1.9 and 1.10 of the Commission's Rules of Practice and Procedure. All such petitions or protests must be filed within 30 days after the date of publication of this notice and must be served on the applicant. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

A-55c
Sample Filings
10/1/83

THE INDUSTRIAL COGENERATION MANUAL

Prest Enterprises, Inc.

468 Plum Avenue
P. O. Box 7065
Memphis, Tennessee 38107-0065
Phone (901) 525-8865

August 31, 1983

Federal Energy Regulatory Commission
Office of the Secretary
825 North Capitol Street, NE
Washington, D. C. 20426

QF 83-418-000

SUBJECT: Application for Commission Certificate of
Qualifying Status of a Cogeneration Facility
(18 CFR 292.207) and Confirmation of Exemption
from Incremental Pricing (18 CFR 292.205)

Gentlemen:

Request Commission certification, as allowed by
18 CFR 292.207 that PREST ENTERPRISES, INC., Memphis,
Tennessee cogeneration facility is a qualifying cogen-
eration facility, and confirmation of its exemption
from incremental pricing per 18 CFR 292.205.

Name and address of applicant

Prest Enterprises, Inc.
468 Plum Avenue
Memphis, TN 38107-0065

Location of facility

468 Plum Avenue
Memphis, TN 38107

Description of facility

The facility which will provide process steam for dry
kilns, consist of one (1) 45,000 lb/hr steam boiler, a steam
turbine, an induction generator, necessary piping and controls.
It is a cogeneration facility wherein the steam from the boi-
ler passes through the turbine and is used to generate elec-
tricity. The exhaust steam from the turbine is used in the
lumber drying kilns.

Primary energy source

Wood waste

Power production Capacity of the facility

This system will be capable of producing 200 KW of electrical
power.

DO NOT REMOVE
FROM OFI

A-55d
Sample Filings
10/1/83

A-6

APPENDIX "B"

MISSISSIPPI PUBLIC SERVICE COMMISSION
JACKSON, MISSISSIPPI

SPECIAL RULE FOR COGENERATION AND SMALL POWER PRODUCTION

SECTION I. DEFINITIONS.

A. GENERAL RULE. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this rule as they have under PURPA, unless further defined in this rule.

B. DEFINITIONS. The following definitions apply for purposes of this rule.

1. "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

2. "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the qualifying facility.

3. "Commission" means the Mississippi Public Service Commission.

4. "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs actually incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility.

5. "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

6. "Long-term contract" means a contract which is for a term greater than one year.

7. "Maintenance power" means electric energy or capacity supplied by an electric utility to a qualifying facility during scheduled outages of the qualifying facility.

8. "New qualifying facility capacity" means electric capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

9. "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

10. "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of the Federal Energy Regulatory Commission's Regulations under Section 201 of the Public Utility Regulatory Policies Act of 1978 as in effect on the effective date of this rule.

11. "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

12. "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

13. "Supplementary power" means electric energy or capacity supplied by an electric utility and regularly used by a qualifying facility in addition to that which the facility generates itself.

14. "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to the utility's customers or is imminently likely to endanger life or property.

SECTION II. GENERAL PROVISIONS.

A. APPLICABILITY. This rule applies to the regulation of sales and purchases between qualifying facilities and electric utilities subject to the Commission's jurisdiction in this matter.

B. NEGOTIATED RATES OR TERMS.

1. Any electric utility and qualifying facility may agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this rule.

2. Nothing in this rule shall affect the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

3. Any contract entered into between a qualifying facility and an electric utility for any purchase shall comply with applicable rules, regulations, practices and procedures of the Commission in effect at the date of execution of the contract.

4. No electric utility may unreasonably refuse to negotiate and enter into a long-term contract for the purchase of energy and/or capacity from a qualifying facility in accordance with the provisions of this rule.

C. REVIEW AND APPROVAL OF CONTRACTS. All contracts between the utility and any qualifying facility executed subsequent to the date of the adoption of these rules by the Commission shall

be filed with the Commission. Upon filing, the Commission may, within 30 days, approve the contract with a finding that it is just and reasonable, and in the public interest, or order further review of the contract prior to approval. If the Commission has not ordered further review of the contract within 30 days from the date of filing, the contract shall be automatically approved.

D. CONFIDENTIALITY.

1. Any data or information furnished by a qualifying facility to a utility during negotiations which is specified as confidential and privileged shall be treated by the utility as confidential and privileged, and

2. Any data or information furnished by a utility to a qualifying facility during negotiations which is specified as confidential and privileged shall be treated by the qualifying facility as confidential and privileged.

SECTION III. INTERCONNECTION AND WHEELING.

A. OBLIGATION TO INTERCONNECT.

1. Subject to A.2 and D. of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this rule.

2. No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

3. Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with such standards for system safety and operating reliability as may be established by the Commission under D.3. of this section.

4. No qualifying facility may have at any one location or facility interconnection with more than one electric utility.

B. TRANSMISSION TO OTHER ELECTRIC UTILITIES
(WHEELING).

1. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. The cost of such transmission may be recovered by the transmitting utility from the qualifying facility pursuant to the regulatory authority having jurisdiction. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this rule as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to Section IV and shall not include any charges for transmission.

2. The Commission shall be informed by the qualifying facility of any request made by the qualifying facility to an electric utility for the transmission of energy and/or capacity to another utility.

C. INTERCONNECTION COSTS. Each qualifying facility shall be obligated to pay any interconnection costs in excess of the costs to either party which would have been incurred had the facility not been a qualifying facility. Each utility shall make provision in its contracts with qualifying facilities or in its standard rates for purchases for the repayment of excess interconnection costs. Should the parties fail to agree, the Commission may determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time. Such determination shall include, among other concerns, consideration of the adequacy of security for any deferred payments.

D. OPERATING SAFETY AND RELIABILITY.

1. In no event shall a qualifying facility interconnect with an electric utility's system without the knowledge and written consent of the utility.

2. The qualifying facility shall be responsible for the design, installation and safe operation of all equipment and facilities on the qualifying facility's side of the point of interconnection and shall be subject to the requirements of all governmental agencies asserting safety jurisdiction and shall comply with all applicable codes, ordinances, rules and regulations thereof.

3. The Commission may establish reasonable standards to ensure system safety and reliability of interconnected operations.

4. Each electric utility shall establish reasonable standards for interconnection with qualifying facilities to ensure system safety and for the protection of the electric utility's equipment and personnel.

5. The qualifying facility shall be responsible for establishing, providing and paying the associated cost of appropriate

operating communications with the utility. The utility shall advise the qualifying facility in meeting this requirement.

6. A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(a) provided by agreement between such qualifying facility and electric utility; or

(b) ordered under Section 202(c) of the Federal Power Act.

7. During any system emergency, an electric utility may discontinue:

(a) purchases from a qualifying facility if such purchases would contribute to such emergency; and

(b) sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

SECTION IV. PURCHASES FROM QUALIFYING FACILITIES.

A. OBLIGATION TO PURCHASE. Subject to paragraph B of this Section, each electric utility shall purchase, in accordance with this rule, any energy and/or capacity which is made available from a qualifying facility:

1. directly to the electric utility; or

2. indirectly to the electric utility in accordance with Section III.B.

B. PERIODS DURING WHICH PURCHASES NOT REQUIRED.

During any period when, due to operational circumstances, a utility (or its system, in the case of a utility which belongs to a centrally dispatched pool) would be required, in order to

accommodate purchases from qualifying facilities, to alter its dispatch of generating units in a manner which would result in a net increase in operating costs to the electric utility, the utility shall be allowed to discontinue those purchases which would otherwise necessitate such alteration of the utility's dispatching; provided, however, that the utility gives reasonable notice to each affected qualifying facility in time for the qualifying facility to discontinue the delivery of energy or capacity to the electric utility.

2. Any utility which fails to comply with the notification requirements of B.1. of this Section is required to pay the qualifying facility the same amount as would have been paid had purchases from the qualifying facility not been discontinued.

3. A claim by an electric utility that such a period has occurred or will occur is subject to such verification by the Commission as the Commission determines necessary or appropriate, either before or after the occurrence.

C. RATES FOR PURCHASES.

1. Rates for purchases shall:

(a) be just and reasonable to the electric consumer of the utility and in the public interest; and

(b) not discriminate against qualifying cogeneration and small power production facilities; and

(c) not be required to exceed the avoided costs of the utility; and

(d) be negotiated (except for rates set under Section IV.C.3 of this rule) and, if the parties fail to agree, either party may submit the issue to the Commission which will resolve the matter on a case by case basis.

2. Relationship to avoided costs.

(a) A rate for purchases satisfies the requirements of C.1.(a), (b), and (c) if the rate equals the avoided costs determined after consideration of the factors set forth in C.5. of this section; except that,

(b) a rate for purchases from other than new qualifying facility capacity may be less than the avoided cost if the Commission determines that a lower rate is consistent with C.1.(a), (b), and (c), and is sufficient to encourage cogeneration and small power production.

(c) Rates for purchases from new qualifying facility capacity shall be in accordance with C.2.(a) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(d) In the case in which the rates for purchases are based upon estimates of avoided costs to be paid over the specific term of the contract or other legally enforceable obligation or are standard rates for purchases as provided in C.3. of this Section, the rates for such purchases do not violate this rule if the rates for such purchases differ from avoided costs at the time of delivery.

3. Standard rates for purchases

(a) There shall be put into effect, not later than six (6) months from the date this rule becomes effective, standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(b) Standard rates for purchases:

(1) shall be filed for approval by the electric utility with the Commission.

(2) shall be consistent with Section IV.C.1.
(a), (b) and (c), and IV.C.5; and

(3) may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies; and

(4) shall specify those terms and conditions of service necessary for application of the rate.

4. Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(a) to provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(b) to provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(1) the avoided costs calculated at the time of delivery; or

(2) the avoided costs calculated at the time the obligation is incurred.

5. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(a) Data provided by the utility pursuant to Section 292.302 of the Federal Energy Regulatory Commission's Regulations under Section 210 of PURPA.

(b) The availability of capacity and energy from a qualifying facility during the system daily and seasonal peak periods, including:

(1) The ability of the utility to dispatch the qualifying facility;

(2) The expected or demonstrated reliability of the qualifying facility;

(3) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(4) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(5) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies including its ability to separate its load from its generation;

(6) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;

(7) The smaller capacity increments and the shorter lead times available when capacity is added from qualifying facilities;

(c) the relationship of the availability of energy and capacity from the qualifying facility to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(d) the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric

utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

D. RECOVERY OF COST OF PURCHASES. All costs, net of costs associated with interconnection or otherwise recovered from the qualifying facility, incurred by an electric utility for purchases of power and/or energy from a qualifying facility pursuant to a standard rate for purchase or other legally enforceable obligations as provided in Section IV, Paragraph C hereof shall be treated by the electric utility as a cost of purchased power.

SECTION V. SALES TO QUALIFYING FACILITIES.

A. OBLIGATIONS TO SELL.

1. Each electric utility shall sell to any qualifying facility, any energy and capacity requested by the qualifying facility at such character of service as ordinarily available.

2. Upon request of a qualifying facility, each electric utility shall provide:

- (a) supplementary power;
- (b) back-up power;
- (c) maintenance power; and/or
- (d) interruptible power.

3. The Commission may waive any requirement of A.2. of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the Commission finds that compliance with such requirement will:

- (a) impair the electric utility's ability to render adequate service to its customers; or

(b) place an undue burden on the electric utility.

B. RATES FOR SALES.

1. Rates for sales shall:

(a) be just and reasonable and in the public interest; and

(b) not discriminate against any qualifying facility in comparison to rates for sales to other customers with similar load or other cost-related characteristics served by the electric utility.

2. Rates for sales of supplementary, back-up, maintenance and/or interruptible power may be negotiated by the parties, subject to Commission approval pursuant to Section II.C. of this rule.

3. Rates for sales of back-up and maintenance power shall:

(a) not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(b) take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

SECTION VI. RESOLUTION OF DISPUTES.

A. PROCEDURE. A proceeding to resolve a dispute between an electric utility and a qualifying facility arising under this rule may be instituted by either party filing a complaint or a formal complaint with the Commission in accordance with the Rules of Practice and Procedure of the Commission.

B. COMMISSION RESOLUTION OF DISPUTES RELATED TO CONTRACTS.

If a contract has not been successfully negotiated within 90 days after submission of a written proposal by the qualifying facility, or of a written request to the utility for a proposal; or, if there is an alleged breach of an existing contract or a dispute between the parties as to interpretation of an existing contract, the Commission may, in its discretion on a case-by-case basis, provide a resolution of the specific matters at issue according to the following procedures:

1. The qualifying facility or the electric utility may petition the Commission for informal arbitration of the specific matters in dispute, naming the other party as respondent.

2. Upon receipt of a petition from either party, and of a certificate of service of the petition upon the other party, the Commission shall assign the case to one or more members of its staff, who will conduct informal arbitration on an expedited basis and issue a written decision within 30 days, except that:

3. Within 30 days of the issuance of the staff decision either party may bring a formal complaint to the Commission from any part of the decision. If no formal complaint has been filed within 30 days, the staff decision will become final and binding upon the parties as an Order of the Commission.

4. Commission proceedings upon the appeal of a staff decision will be conducted according to the Commission's existing rules for the formal adjudication of cases, except that to the extent possible, an expedited schedule will be maintained which will permit issuance of the Commission's final decision within 90

days of the staff decision from which the appeal was taken. The Commission's decision will be in the form of an Order and will be final and binding upon the parties subject to appeal.

SECTION VII. EXEMPTION FROM REGULATION.

All qualifying facilities are exempted from Mississippi State laws and regulations, other than those promulgated herein, respecting:

- (1) The rates of electric utilities; and
- (2) The financial and organizational regulation of electric utilities.

APPENDIX "C"



THE INDUSTRIAL COGENERATION MANUAL

II AMERICAN PAPER INST. v. AMERICAN ELEC. POWER

Syllabus

§210(e)(3) of PURPA, which provides that "no qualifying small production facility or qualifying cogeneration facility may be exempted under this subsection from" specified provisions of the Federal Power Act (FPA) which require FERC to afford an opportunity for a hearing before ordering an interconnection.

Held:

1. FERC did not act arbitrarily or capriciously in promulgating the full-avoided-cost rule, which is the maximum rate permissible under §210(b). Such rule plainly satisfies the requirement of §210(b) that the rate not discriminate against qualifying cogeneration and small power production facilities. FERC also adequately explained why the rate is "just and reasonable to the electric consumers of the electric utility and in the public interest." Both the statutory language and the legislative history confirm that Congress did not intend to impose traditional rate-making concepts on sales by qualifying facilities to utilities. And although FERC recognized that the rule would not directly provide any rate savings to consumers, it reasonably deemed it more important at this time that the rule would provide a significant incentive for the development of cogeneration and small power production, and that ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels and the more efficient use of energy. Pp. 9-15.

2. Nor did FERC exceed its authority in promulgating the interconnection rule. The authority granted by §210(a) to promulgate such rules as are necessary to require utilities to deal with qualifying facilities plainly encompasses the power to promulgate rules requiring utilities to make physical connections with such facilities, and FERC reasonably interpreted §210(e)(3) as forbidding FERC to exempt qualifying facilities from being the "target" of interconnection applications by other facilities under the FPA, but not as forbidding FERC to grant qualifying facilities the right to obtain interconnections under PURPA without applying for an order under the FPA. Such interpretation is supported by the purposes of PURPA and the statutory scheme created by both Acts. Pp. 15-20.

— U. S. App. D. C. —, 675 F. 2d 1226, reversed and remanded.

MARSHALL, J., delivered the opinion of the Court, in which all other Members joined, except POWELL, J., who took no part in the consideration or decision of the cases.

NOTE: Where it is feasible, a syllabus (headnote) will be released, as is being done in connection with this case, at the time the opinion is issued. The syllabus constitutes no part of the opinion of the Court but has been prepared by the Reporter of Decisions for the convenience of the reader. See *United States v. Detroit Lumber Co.*, 200 U. S. 321, 337.

SUPREME COURT OF THE UNITED STATES

Syllabus

AMERICAN PAPER INSTITUTE, INC. v. AMERICAN ELECTRIC POWER SERVICE CORP. ET AL.

CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 82-34. Argued March 22, 1983—Decided May 16, 1983*

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) was designed to encourage the development of cogeneration facilities and small power production facilities and to reduce the demand for fossil fuels. Section 210(a) directs the Federal Energy Regulatory Commission (FERC) to prescribe the rules requiring electric utilities to deal with qualifying cogeneration and small power facilities. With respect to utilities' purchases of electricity from such facilities, §210(b) provides that rates set by FERC "shall be just and reasonable to the electric consumers of the electric utility and in the public interest," shall not discriminate against qualified cogeneration and small power facilities, and shall not exceed "the incremental cost to the electric utility of alternative electric energy." Following rulemaking proceedings, FERC promulgated a rule requiring utilities to purchase electric energy from a qualifying facility at a rate equal to the utility's "full avoided cost," i. e., the cost to the utility which, but for the purchase from the qualifying facility, would be incurred by the utility in generating the electricity itself or purchasing the electricity from another source. FERC also promulgated a rule requiring utilities to make such physical interconnections with cogenerators and small power producers as are necessary to effect purchases or sales of electricity authorized by PURPA. Upon review, the Court of Appeals vacated both rules, holding that FERC had not adequately explained its adoption of the full-avoided-cost rule, and that it exceeded its statutory authority in promulgating the interconnection rule, in view of

*Together with No. 82-226, *Federal Energy Regulatory Commission v. American Electric Power Service Corp. et al.*, also on certiorari to the same court.

2 AMERICAN PAPER INST. v. AMERICAN ELEC. POWER

plained its adoption of the full-avoided-cost rule, and that it exceeded its statutory authority in promulgating the interconnection rule. 675 F.2d 1221 (CA DC 1982). We reverse.

I A

Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities.¹ As we noted in *FERC v. Mississippi*, — U. S. —, — (1982) (footnote omitted), "Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels," and it recognized that electric utilities had traditionally been "reluctant to purchase power from, and to sell power to, the nontraditional facilities." Accordingly, Congress directed FERC to prescribe, within one year of the statute's enactment, rules requiring electric utilities to deal with qualifying cogeneration and small power production facilities. PURPA §210(a), 16 U. S. C. §824a-3(a) (Supp. V). With respect to the purchase of electricity from cogeneration and small power production facilities, Congress provided that the rate to be set by the Commission

"(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative elec-

¹The statute defines a "cogeneration facility" as a facility that produces both electric energy and steam or some other form of useful energy, such as heat. 16 U. S. C. §796(18)(A) (Supp. V). A "small power production" facility is a facility that has a production capacity of not more than 80 megawatts and produces electric power from biomass, waste, or renewable resources such as wind, water, or solar energy. 16 U. S. C. §796(17)(A) (Supp. V).

NOTICE: This opinion is subject to formal revision before publication in the preliminary print of the United States Reports. Readers are requested to notify the Reporter of Decisions, Supreme Court of the United States, Washington, D. C. 20543 of any typographical or other formal errors, in order that corrections may be made before the preliminary print goes to press.

SUPREME COURT OF THE UNITED STATES

Nos. 82-34 AND 82-226

AMERICAN PAPER INSTITUTE, INC., PETITIONER

82-34

v.
AMERICAN ELECTRIC POWER SERVICE
CORPORATION ET AL.FEDERAL ENERGY REGULATORY COMMISSION,
PETITIONER

82-226

v.
AMERICAN ELECTRIC POWER SERVICE
CORPORATION ET AL.ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF
APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

[May 16, 1983]

JUSTICE MARSHALL delivered the opinion of the Court. This case concerns two rules promulgated by the Federal Energy Regulatory Commission (FERC) pursuant to §210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U. S. C. §824a-3 (Supp. V). The first rule requires electric utilities to purchase electric energy from cogenerators and small power producers at a rate equal to the purchasing utility's full avoided cost, i. e., the cost the utility would have incurred had it generated the electricity itself or purchased the electricity from another source. The second rule requires utilities to make such interconnections with cogenerators and small power producers as are necessary to effect purchases or sales of electricity authorized by PURPA. The Court of Appeals held that FERC had not adequately ex-

tric energy." PURPA § 210(b), 16 U. S. C. § 824a-3(b) (Supp. V).

Following rulemaking proceedings, FERC promulgated regulations governing transactions between utilities and those cogeneration and small power production facilities, designated as "qualifying facilities." 18 CFR 292.201-292.207, that may invoke the provisions of PURPA to sell electricity to and purchase electricity from utilities.

The first regulation at issue in this case, 18 CFR 292.304(b) (2) (1982), requires a utility to purchase electricity from a qualifying facility at a rate equal to the utility's full avoided cost. The utility's full avoided cost is "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." PURPA § 210(d), 16 U. S. C. § 824a-3(d) (Supp. V). See 18 CFR 292.101(b)(6) (1982) (the term full "avoided cost" used in the regulations is the equivalent of the term "incremental cost of alternative electric energy" used in § 210(d) of PURPA). In its order accompanying the promulgation of this rule, FERC explained its decision to set the rate at full avoided cost rather than at a level that would result in direct rate savings for utility customers by permitting a utility to obtain energy at a cost less than the cost to the utility of producing the energy itself or purchasing it from an alternative source. 45 Fed. Reg. 12214 (Feb. 15, 1980). The Commission emphasized the need to provide incentives for the development of cogeneration and small power production:

"[I]n most instances, if part of the savings from cogeneration and small power production were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual consumer. On the other hand, if these savings are allocated to the relatively small class of qualifying cogenerators and small power producers, they may provide a significant incentive for a higher growth rate of these technologies."

Id., at 12222.

The Commission noted that "ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy." *Ibid.*

FERC rejected proposals that it set the rate for the purchase of electricity from qualifying facilities at a fixed percentage of the purchasing utility's full avoided cost:

"[I]n most situations, a qualifying cogenerator or small power producer will only produce energy if its marginal cost of production is less than the price he receives for its output. If some fixed percentage is used, a qualifying facility may cease to produce additional units of energy when its costs exceed the price to be paid by the utility. If this occurs, the utility will be forced to operate generating units which either are less efficient than those which would have been used by the qualifying facility, or which consume fossil fuel rather than the alternative fuel which would have been consumed by the qualifying facility had the price been set at full avoided cost." *Id.*, at 12222-12223.

The second regulation at issue here, 18 CFR 292.303 (1982), provides that electric utilities shall purchase electricity made available by qualifying facilities, sell electricity to qualifying facilities upon request, and, most important for present purposes, "make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart." 18 CFR 292.303(c)(1) (1982). An interconnection is a physical connection that allows electricity to flow from one entity to another.²

²In an accompanying regulation, FERC directed that each qualifying facility "pay any interconnection costs which the State regulatory authority . . . or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis." 18 CFR § 292.306 (a).

In its order the Commission rejected the contention that § 210(e)(3) of PURPA requires it to afford an opportunity for an evidentiary hearing to any utility that is unwilling to make an interconnection with a qualifying facility that has invoked the provisions of PURPA to enter into a purchase or sale with the utility. Section 210(e)(3) provides in relevant part:

"No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(B) the provisions of section 210 . . . or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act . . ."

Sections 210 and 212 of the Federal Power Act (FPA), 16 U. S. C. §§ 824i and 824k (Supp. V), describe the procedure to be followed by FERC when an electric utility, Federal power marketing agency, cogenerator, or small power producer applies for an order requiring another such facility to make an interconnection. Section 210 provides that, upon receipt of an application for an order requiring an interconnection, the Commission shall issue notice to each affected State regulatory authority, utility, Federal power marketing agency, and owner or operator of a cogeneration facility or small power production facility, and to the public, § 210(b)(1), 16 U. S. C. § 824i(b)(1) (Supp. V), afford an opportunity for an evidentiary hearing, § 210(b)(2), 16 U. S. C. § 824i(b)(2) (Supp. V), and issue an order approving the application only if it determines that approval

"(1) is in the public interest,

(2) would—

- (A) encourage overall conservation of energy or capital,
- (B) optimize the efficiency of use of facilities and resources, or
- (C) improve the reliability of any electric utility system

or Federal power marketing agency to which the order applies, and

(3) meets the requirements of (§ 212 of the FPA)."

Section 212 of the FPA, 16 U. S. C. § 824k (Supp. V), provides that an order approving an interconnection under § 210 may be issued only if the Commission determines that the interconnection is not likely to result in a reasonably ascertainable uncompensated loss for any electric utility, cogenerator, or small power producer, impose an undue burden on any such facility, unreasonably impair the reliability of any electric utility, or impair the ability of any electric utility to supply adequate service to its customers.¹

¹Section 212 of the FPA provides in pertinent part:

"(a) No order may be issued by the Commission under section 824i [FPA § 210] . . . of this title unless the Commission determines that such order—
(1) is not likely to result in a reasonably ascertainable uncompensated loss for any electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

(2) will not place an undue burden on an electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

(3) will not unreasonably impair the reliability of any electric utility affected by the order; and

(4) will not impair the ability of any electric utility affected by the order to render adequate service to its customers.

The determination under paragraph (1) shall be based upon a showing of the parties. The Commission shall have no authority under section 824i . . . of this title to compel the enlargement of generating facilities.

"(b) No order may be issued under section 824i . . . of this title unless the applicant for such order demonstrates that he is ready, willing, and able to reimburse the party subject to such order for

(1) in the case of an order under section 824i of this title, such party's share of the reasonably anticipated costs incurred under such order.

"(d) If the Commission does not issue any order applied for under section 824i . . . of this title, the Commission shall, by order, deny such application and state the reasons for such denial.

"(e) No provision of section 824i . . . of title is title shall be treated—

In concluding that an evidentiary hearing under the FPA is not required prior to an interconnection necessary to complete a purchase or sale authorized by PURPA, the Commission reasoned that § 210(a) of PURPA "provides a general mandate for the Commission to prescribe rules necessary to encourage cogeneration and small power production." 45 Fed. Reg., at 12221. The Commission also emphasized that "a basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators," and that "to require facilities to go through the complex procedures set forth in section 210 of the Federal Power Act would, in most circumstances, significantly frustrate" the achievement of that purpose. *Ibid.*

Following the filing of several petitions for rehearing, the Commission issued an order adhering to both the full-avoided-cost rule and the interconnection rule. 45 Fed. Reg. 33958 (May 15, 1980).

B

Respondents American Electric Power Service Corp., Consolidated Edison Co. of New York, Inc., and Colorado-Ute Electric Association, Inc., sought review of the Commission's rules in the United States Court of Appeals for the District of Columbia. The Court of Appeals vacated both rules. 675 F. 2d 1226 (1982).

The Court of Appeals concluded that FERC had not adequately demonstrated that the full-avoided-cost rule was consistent with the mandate of § 210(b) of PURPA that the Commission prescribe rates for purchases of electric energy from qualifying facilities that are "just and reasonable to the electric consumers of the electric utility" and "in the public interest." 675 F. 2d, at 1232. "By ordering that the purchase

- (1) as requiring any person to utilize the authority of such section 824i . . . of this title in lieu of any other authority of law, or
- (2) as limiting, impairing, or otherwise affecting any authority of the Commission under any other provision of law."

rate be equal to the full avoided cost in every case, FERC has, without convincing explanation, simply adopted as a uniform rule the maximum rate specified in the statute." *Id.*, at 1233.⁴ The court stressed that "FERC should allocate the benefits more evenly between the cogenerators and the utilities if the utilities can demonstrate that, under a percentage of avoided cost approach, an allocation less heavily favoring the cogenerators is in the public interest and the interest of the utilities' electric consumers, and will not disproportionately discourage cogeneration." *Ibid.* While acknowledging that an approach requiring calculation of each cogenerator's costs on a case-by-case basis "would indeed veer toward the public utilities-style rate setting that Congress wanted to avoid," the Court of Appeals emphasized that FERC should have given additional consideration to a percentage-of-avoided-cost approach, whereby FERC would either set a percentage itself or establish a range within which each state regulatory commission could fix a precise percentage. *Ibid.*⁵

The Court of Appeals held that FERC had exceeded its authority in promulgating the interconnection rule. The court reasoned that the "relatively specific limitation on authority in PURPA section 210(e)(3) . . . must control over the relatively general grant of authority in FPA section 212(e)." 675 F. 2d, at 1240 (emphasis in original). The court concluded that the Commission must provide notice to interested parties and afford an opportunity for an evidentiary hearing with

⁴With respect to the Commission's statement that any savings to consumers that a lower rate might produce would be insignificant in comparison to the benefit to qualifying facilities provided by the full-avoided-cost rate, the court suggested that the Commission had failed to "bear in mind, as Congress surely knew, that inevitably the impact of FERC's rules per consumer will be less than their impact per cogenerator." 675 F. 2d, at 1234.

⁵The court proceeded to "outline some additional concerns raised by the full avoided cost rule, which the Commission should address in its subsequent rulemaking." 675 F. 2d, at 1233. See *id.*, at 1234-1236.

respect to each interconnection requested by a qualifying facility.

Following the denial of petitions for rehearing and rehearing *en banc*,⁴ petitions for certiorari were filed by both FERC and American Paper Institute, Inc., the national trade association of the pulp, paper and paperboard industry, which accounts for a large share of the cogeneration of electric power in the United States today. We granted both petitions. — U. S. — (1982).

II

The first question before us is whether FERC's action in promulgating the full-avoided-cost rule was "arbitrary, capricious, [or] an abuse of discretion." 5 U. S. C. § 706(2)(A).⁵

⁴In denying a petition for rehearing, the Court of Appeals emphasized that it had not declared the full-avoided-cost rule inconsistent with PURPA but had "simply remanded the matter because the Commission had failed to explain 'its rationale and process of consideration.'" 675 F. 2d 1246 (1982), quoting 675 F. 2d, at 1233. A suggestion for rehearing *en banc* was denied by a vote of three to two, with six of the 11 active Circuit judges not participating. 675 F. 2d 1246 (1982).

⁵It is not entirely clear from the Court of Appeals' opinion what standard of review the court applied, but it appears that the court may have erroneously employed the substantial-evidence standard. The court criticized FERC for failing "to demonstrate the factual basis," 675 F. 2d, at 1241, for its finding that sharing the savings from cogeneration with consumers would afford consumers only insubstantial savings, and it cited in a footnote an earlier decision that had employed the substantial-evidence test in a case involving informal rulemaking by the Commission under the FPA. *Id.*, at 1234 n. 36, citing *Public Systems v. FERC*, 606 F. 2d 973 (CA10 1979).

In any event, the Court of Appeals should have applied only the arbitrary and capricious standard. Unlike the FPA, see 16 U. S. C. § 825(b), PURPA does not direct reviewing courts to determine whether orders entered thereunder are supported by substantial evidence. In the absence of a specific command in PURPA to employ a particular standard of review, the full-avoided-cost rule must be reviewed solely under the more lenient arbitrary and capricious standard prescribed by the Administrative Procedure Act for judicial review of informal rulemaking. See, e. g., *CCC v. National Citizens Committee for Broadcasting*, 436 U. S. 775, 803

We cannot answer this question simply by noting that the full-avoided-cost rule is within the range of permissible rates that Congress established in § 210(b) of PURPA. The Commission plainly has the authority to adopt a full-avoided-cost rule, for PURPA sets full avoided cost as the maximum rate that the Commission may prescribe. Whether the Commission properly exercised that authority is a separate issue. To decide whether the Commission's action was "arbitrary, capricious, [or] an abuse of discretion," we must determine whether the agency adequately considered the factors relevant to choosing a rate that will best serve the purposes of the statute, and whether the agency committed "a clear error of judgment." *Citizens to Preserve Overton Park v. Volpe*, 401 U. S. 402, 416 (1971).

FERC's explanation of its reasons for promulgating the full-avoided-cost rule must be examined in light of the criteria set forth in § 210(b) of PURPA, 16 U. S. C. § 824a-3(b) (Supp. V), which provides that the purchase rate established by the Commission must be "just and reasonable to the electric consumers of the electric utility and in the public interest" and must not discriminate against qualifying facilities.⁶ Since the full-avoided-cost rule plainly satisfies the nondiscrimination requirement, we need only consider whether FERC adequately explained why the rule is "just and reasonable to the electric consumers of the electric utility and in the public interest."

We cannot accept respondents' suggestion, Brief at 9 and n. 4, that the "just and reasonable" language in § 210(b) was intended to require that the purchase rate be set "at the low-

(1978).

⁶See also H. R. Conf. Rep. No. 95-1750, 95th Cong., 2d Sess. 98 (1978) (the purchase rate prescribed by the Commission is to be "the lower of . . . a rate which is just and reasonable to consumers of the utility, in the public interest, and nondiscriminatory, or the incremental cost of alternate electric energy").

est possible reasonable rate consistent with the maintenance of adequate service in the public interest."¹⁰ *Atlantic Refining Co. v. Public Service Comm'n of New York*, 360 U. S. 378, 388 (1959), quoting the original version of the Natural Gas Act. Simply on the basis of the statutory language, we would be reluctant to infer that Congress intended the terms "just and reasonable," which are frequently associated with cost-of-service utility ratemaking, see, e.g., *NAACP v. FPC*, 425 U. S. 662, 666 (1976), to adopt a cost-of-service approach in the very different context of cogeneration and small power production by nontraditional facilities. The legislative history confirms, moreover, that Congress did not intend to impose traditional ratemaking concepts on sales by qualifying facilities to utilities. The Conference Report states in pertinent part:

"It is not the intention of the conferees that cogenerators and small power producers become subject . . . to the type of examination which is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power. The conferees recognize that cogenerators and small power producers are different from electric utilities, not being guaranteed a rate of return on their activities generally or on the activities vis-a-vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable.

" . . . [C]ogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications, but rather in a less burdensome manner. The establishment of utility type regulation over them would act as a significant disincentive to firms

interested in cogeneration and small power production." H. R. Conf. Rep. No. 95-1750, *supra*, at 97-98.

In contrast, a subsequent passage in the Conference Report explicitly states that the "just and reasonable" language of § 210 (c), 16 U. S. C. § 824a-3(c), which concerns sales by utilities to qualifying facilities, "is intended to refer to traditional utility ratemaking concepts." H. R. Conf. Rep. No. 95-1750, *supra*, at 98 (emphasis added).

The Commission did not ignore the interest of electric utility consumers "in receiving electric energy at equitable rates." H. R. Conf. Rep. No. 95-1750, *supra*, at 97.¹¹ The Commission recognized that the full-avoided-cost rule would not directly provide any rate savings to electric utility consumers, but deemed it more important that the rule could "provide a significant incentive for a higher growth rate" of cogeneration and small power production, and that "these ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy."¹² 45 Fed. Reg., at 12222.

¹⁰We interpret the "just and reasonable" language of § 210(b) to require consideration of potential rate savings for electric utility consumers. Of course, even when utilities purchase electric energy from qualifying facilities at full avoided cost rather than at some lower rate, the rates the utilities charge their customers will not be increased, for by hypothesis the utilities would have incurred the same costs had they generated the energy themselves or purchased it from other sources. Moreover, a utility's existing rates will ordinarily have been determined to be "just and reasonable" by the appropriate state regulatory authority. But it does not follow that the full-avoided-cost rule is necessarily "just and reasonable to the electric consumers of the electric utilities" within the meaning of § 210(b) of PURPA. Unless the "just and reasonable" language is to be regarded as mere surplusage, it must be interpreted to mandate consideration of rate savings for consumers that could be produced by setting the rate at a level lower than the statutory ceiling.

¹¹A decrease in the utilities' reliance on fossil fuels may result in a reduction of the prices of those fuels to levels lower than would have been the case with higher demand. Since the rates the utilities are permitted to

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As the Commission explained, a purchase rate established at a fixed percentage of avoided cost would discourage production of electric energy by qualifying facilities whose marginal costs exceeded the rate that a purchasing utility would be required to pay under this approach, whereas those same facilities would retain an incentive to produce energy under the full-avoided-cost rule so long as their marginal costs did not exceed the full avoided cost of the purchasing utility. *Id.*, at 1222-1223.

The Commission would have encountered considerable difficulty had it attempted to determine an appropriate rate less than full avoided cost. A wide variety of technologies are used in cogeneration and small power production, including internal combustion engines, steam turbines, combustion turbines, windmills, solar cells, and hydro turbines. Facilities may vary greatly in capacity. It would have been extremely difficult, if not impossible, for the Commission to make any useful estimate of the amount of cogeneration and small power production that would be discouraged by setting the rate at a level lower than full avoided cost.

It bears emphasizing that the full-avoided-cost rule is not as inflexible as might appear at first glance. First, any state regulatory authority and any nonregulated utility may apply to the Commission for a waiver of the rule. A waiver may be granted if the applicant demonstrates that a full-avoided-cost rate is unnecessary to encourage cogeneration and small power production. 18 CFR 292.403 (1982). Second, a qualifying facility and a utility may negotiate a contract setting a price that is lower than a full-avoided-cost rate. 18 CFR 292.301(b)(1) (1982). Because the full-avoided-cost rule is subject to revision by the Commission as it obtains experience with the effects of the rule, it may often be in the inter-

charge their customers are based on their costs, electric utility customers can expect to share in the savings to the utilities resulting from reduced fuel prices.

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est of a qualifying facility to negotiate a long-term contract at a lower rate. The Commission's rule simply establishes the rate that applies in the absence of a waiver or a specific contractual agreement.

Under these circumstances it was not unreasonable for the Commission to prescribe the maximum rate authorized by PURPA.¹⁸ The Commission's order makes clear that the Commission considered the relevant factors and deemed it most important at this time to provide the maximum incentive for the development of cogeneration and small power production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the nation's dependence on fossil fuels. The Commission has a statutory mandate to set a rate that is "in the public interest," and as this Court stated in *NAACP v. FPC*, *supra*, at 669, "the words 'public interest' in a regulatory statute . . . take meaning from the purposes of the regula-

"We reach this conclusion even though we agree with the Court of Appeals, see note 4, *supra*, that the rule was not adequately explained by the Commission's observation that "in most instances, if part of the savings from cogeneration and small power production were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual consumer," whereas the rule would provide significant incentives for cogenerators and small power producers. 45 Fed. Reg., at 12222. In the context of rate-making, it is typically the case that any increment in the rate will "make a small dent in the consumer's pocket." *FPC v. Texaco, Inc.*, 417 U. S. 380, 399 (1974), while that same increment will have substantial consequences for the parties to whom the rate is paid. FERC's statutory mandate to prescribe a rate that "shall be just and reasonable to the electric consumers of the electric utility," 16 U. S. C. § 821a-3 (b) (1), obviously reflects a congressional determination that potential savings for consumers as a class are important even though rate changes will generally not have great economic significance for any individual consumer. Cf. *FPC v. Texaco, supra*, at 399 ("Even if the effect of increased small-producer prices would make a small dent in the consumer's pocket, . . . the [Natural Gas] Act makes unlawful all rates which are not just and reasonable, and does not say a little unlawfulness is permitted.")

tory legislation." The basic purpose of §210 of PURPA was to increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels. See *FERC v. Mississippi*, *supra*, at ——. At this early stage in the implementation of PURPA, it was reasonable for the Commission to prescribe the maximum rate authorized by Congress and thereby provide the maximum incentive for the development of cogeneration and small power production.

III

Absent §210(e)(3) of PURPA, there would be no doubt as to the validity of the Commission's interconnection rule. Section 210(a) of PURPA, 16 U.S.C. §821a-3(a) (Supp. V), provides the Commission with general authority to promulgate

"such rules as it determines necessary to encourage cogeneration and small power production which rules require electric utilities to offer to—

- (1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and
- (2) purchase electric energy from such facilities."

The authority to promulgate such rules as are necessary to require purchases and sales plainly encompasses the power to promulgate rules requiring utilities to make physical connections with qualifying facilities in order to consummate purchases and sales authorized by PURPA. No purchase or sale can be completed without an interconnection between the buyer and seller.

In the absence of a specific provision to the contrary, the Commission's power to promulgate rules under PURPA requiring interconnections would not be negated by the provisions of the FPA that give the Commission the authority to conduct adjudicatory proceedings and issue orders requiring interconnections. As a general matter, the existence of

power to proceed by adjudication under one statute is in no way inconsistent with the existence of power to proceed by rulemaking under another statute. Moreover, there is nothing in the FPA to suggest that the Commission must proceed by adjudication in determining the obligations of facilities within its jurisdiction to make interconnections. On the contrary, Congress expressly provided in §212(e) of the FPA, 16 U.S.C. §242k(e) (Supp. V), that §210 of the FPA shall not be construed "as requiring any person to utilize the authority of [§210] . . . in lieu of any other authority of law," or "as limiting, impairing, or otherwise affecting any authority of the Commission under any other provision of law."

The critical question, therefore, is whether §210(e)(3) of PURPA deprives FERC of the power it would otherwise have under §210(a) of PURPA to promulgate rules requiring utilities to make such interconnections with qualifying facilities as are necessary to effect purchases or sales authorized by the Act. In holding the interconnection rule invalid, the Court of Appeals relied upon what it took to be "the literal meaning" of §210(e)(3), 675 F.2d, at 1240, which states in pertinent part that

"No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(B) the provisions of section 210 . . . or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act . . ."

The Court of Appeals interpreted §210(e)(3) of PURPA to mean that FERC may not promulgate a rule requiring utilities to interconnect with qualifying facilities in order to complete purchases and sales the utilities are required to enter into under PURPA, but must instead afford an opportunity for an evidentiary hearing under §§210 and 212 of the FPA in the case of each purchase and sale.

While the language of §210(e)(3) of PURPA can be so interpreted, the purposes of PURPA strongly support the Commission's contrary reading of that provision. The purposes of the statute make it most unlikely that Congress could have intended that an evidentiary hearing be held for every interconnection necessary to consummate a purchase or sale of electricity authorized by the Act. Evidentiary hearings under §210 of the FPA entail a determination of whether a proposed interconnection (1) is in the public interest, and (2) would encourage overall conservation of energy or capital, optimize the efficiency of use of facilities and resources, or improve the reliability of the affected utility systems. 16 U. S. C. §824(a)(1) (Supp. V). It is highly doubtful that Congress could have intended that the Commission make such a determination every time a qualifying facility seeks to hook up with a utility to complete a purchase or sale under PURPA, for Congress itself determined in enacting PURPA that these purchases and sales are in the public interest, and that the development of cogeneration and small power production will help to conserve energy and capital and ensure the more efficient use of the nation's resources.

Providing an opportunity for evidentiary hearings before the Commission for every interconnection necessary to complete a purchase or sale under PURPA would seriously impede the very development of cogeneration and small power production that Congress sought to facilitate. Many of the facilities in question are small operations. By definition a small power production facility has a production capacity of no more than 80 megawatts, 16 U. S. C. §796(17)(A)(ii) (Supp. V), and cogeneration facilities may also be of modest size. Many owners of qualifying facilities would have little incentive to purchase or sell electric energy if they had to go through an evidentiary hearing before FERC in Washington, D. C., every time they needed to hook up with a utility to consummate a purchase or sale. The average cost to FERC of a contested interconnection proceeding is currently more than \$57,000, see FERC Notice of Proposed Rulemaking, Docket

RM 82-38-000, Fees Applicable to Electric Utilities, Cogenerators, and Small Power Producers, at 29-30 (Sept. 1, 1982), and the costs to private parties are doubtless also substantial. If we were to hold that utilities must be provided an opportunity for a hearing whenever a qualifying facility seeks an interconnection in order to effectuate a purchase or sale under PURPA, we would be "imput[ing] to Congress a purpose to paralyze with one hand what it sought to promote with the other." *Clark v. Uebersee Finanz-Korporation, A.G.*, 332 U. S. 480, 489 (1947). Cf. *E. I. duPont de Nemours & Co. v. Train*, 430 U. S. 112, 132-133 (1977); *Pernian Basis Area Rate Cases*, 390 U. S. 747, 777 (1968).

We agree with the Commission that, in light of the entire statutory scheme, §210(e)(3) of PURPA may reasonably be interpreted to forbid the Commission to exempt qualifying facilities from being the target of applications under the FPA for orders "requiring . . . [a] physical connection," FPA §210(a)(1), but not to forbid the Commission to grant qualifying facilities the right to obtain interconnections without applying for an order under the FPA. The use of the word "exempted" in §210(e)(3) is consistent with an intent to ensure only that qualifying facilities not be immunized from the requirements that the Commission may impose under §§210 and 212 of the FPA. The term "exemption" is ordinarily used to denote relief from a duty or service. See, e. g., Black's Law Dictionary 513 (5th ed. 1979) (to "exempt" is "to relieve, excuse or set free from a duty or service imposed upon the general class to which the individual exempted belongs"). The only duty that §§210 and 212 of the FPA directly impose upon any facility is the duty to obey an order "requiring . . . [a] physical connection." Section 210(e) of the FPA expressly states that §210 of the FPA shall not be construed "as requiring any persons to utilize the authority of [§210] . . . in lieu of any other authority of law." Significantly, the Commission's interconnection rule does not immunize qualifying facilities from the only requirement

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that §§ 210 and 212 of the FPA do directly impose on them—the requirement that they obey an interconnection order issued under those provisions. Qualifying facilities remain subject to applications by other facilities for orders requiring them to make interconnections. The Commission's rule simply permits qualifying facilities to take certain steps to require *other parties*, namely, electric utilities, to make interconnections.¹²

The Commission's interconnection rule represents "a contemporaneous construction of a statute by the men charged with the responsibility of setting its machinery in motion, of making the parts work efficiently and smoothly while they are yet untried and new." *Udall v. Tallman*, 380 U. S. 1, 16 (1965), quoting *Power Reactor Development Co. v. Interna-*

¹²The Commission's interpretation also finds support in the indications in the legislative history of §§ 210 and 212 of the FPA that those provisions were intended to address a different situation. Prior to their enactment, the Commission's authority to order interconnections was limited, under § 202(b) of the FPA, 16 U. S. C. § 824a(b), to utilities over which it had regulatory jurisdiction and, except in emergencies, to situations in which a "person engaged in the *** sale of electric energy" applied for an order directing such a utility to interconnect. Congress was concerned with the refusal of some intrastate utilities to make interconnections with other systems because, had they done so, they would have become part of the interstate system and thereby become subject to the full range of regulation under the FPA. See 124 Cong. Rec. 34763-34764 (1978) (Sen. Metzenbaum); *id.*, at 31770 (Sen. Bartlett); 123 Cong. Rec. 31194 (1977) (Sen. Johnston); *id.*, at 32397-32398 (colloquy between Sen. Johnston and Sen. Domenici). Sections 210, 211, and 212 of the FPA were enacted to give the Commission authority to order interconnections where they will enhance the reliability of the nation's electric power systems and optimize the use of its generating capacity. At the same time, Congress provided, in § 201(b)(2) of the FPA, 16 U. S. C. § 824(b)(2) (Supp. V), that compliance with orders to interconnect issued under § 210 or § 211 would not subject an entity to regulation by the Commission under any other provision of the Act. There is nothing in the legislative history of §§ 210-212 to suggest that they were intended to provide the exclusive means of obtaining an interconnection.

APPENDIX "D"

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

WIND-POWERED ELECTRIC GENERATOR OF A. E. SINNOTT NEAR PINCHER CREEK

Decision D 84-12
Application 840007

1 INTRODUCTION

1.1 The Application

A. E. Sinnott applied, pursuant to sections 14 and 15 of the Hydro and Electric Energy Regulation, for approval to operate a wind-powered electric generator of about 40-kilowatt (kW) capacity, and pursuant to sections 17(2)(a) and (b) of the Hydro and Electric Energy Act, for approval to connect the generator to the electric distribution system of TransAlta Utilities Corporation (TransAlta). The generator is located on his land in the northwest quarter, section 2, township 7, range 30, west of the 4th meridian. He requested that the Board address matters relating to the allocation of costs and other terms and conditions associated with the interconnection.

1.2 The Hearing

The application was considered at a public hearing in Lethbridge, Alberta, on 20 and 21 March 1984, with C. J. Goodman, P.Eng., F. J. Mink, P.Eng., and R. G. Paterson, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table.

1.3 Background

Mr. Sinnott and his family own and operate a 650-hectare farm near the town of Pincher Creek. The operation includes three residences, grain-handling facilities, an anhydrous ammonia fertilizer sales facility, a shop, and other farm facilities. The farm was originally served by a single-phase 230-volt, 25-kilovolt-ampere supply from rural distribution lines. Planned expansion of the overall farming operation requires an electric power supply in excess of the maximum capacity of the single-phase line. A 3-phase power supply has recently been installed by TransAlta at the Sinnott farm.

In view of his expected long-term growth in electric energy requirement, Mr. Sinnott also investigated and decided to purchase a 40-kW wind-powered generator that would meet all his present and future requirements. His present need, however, is significantly below the expected capability of the machine. Mr. Sinnott applied for and received interim approval from the Board to operate his generator and to connect it with TransAlta's system. TransAlta is prepared to purchase all the surplus energy available from his generator.

Mr. Sinnott and TransAlta were unable to agree on a price for his surplus energy, as well as other matters such as sharing of the interconnection and metering costs, and insurance and liability. The application was filed with the Board for resolution of these matters as well as to receive final approval for the operation of the generator and the interconnection with TransAlta's system.

2 APPLICANT'S SUBMISSION

2.1 The Proposed Plant and Interconnection

The applicant stated that, based on recent records, his present electric energy consumption averages about 2000 kilowatt-hours (kWh) per month throughout the year. This is expected to increase to about 6000 kWh per month over the next few years as farming and fertilizer operations are expanded. The maximum monthly consumption may approach 10 000 kWh per month if electric heating is also utilized, but this option depends to a degree on the price that would be paid for surplus energy delivered to TransAlta.

Mr. Sinnott has installed an Enertech Model 44/40, 3-phase 460-volt wind-powered generator, rated at 45 kW at a wind speed of 80 kilometres per hour. He estimated the average annual energy output of his generator to be between 120 000 kWh and 140 000 kWh based on recorded meteorological data at the Lethbridge station. The wind-powered generator has been connected to the local 3-phase distribution system of TransAlta to provide induction power to energize the generator, supply back-up power for Mr. Sinnott's operation during periods when demand exceeds generation or if the generator is not operating, and to facilitate sale of surplus energy to TransAlta.

The applicant stated that his generating facility is constructed and is operating in accordance with Canadian Standards Association standards and Electrical Protection Branch regulations. Voltage and frequency are within generally accepted utility limits. In addition, over- and under-voltage and frequency controls are installed. A disconnect switch is installed to allow the generator to be isolated from TransAlta's distribution system to assure safety of linemen working on the system downstream from the generator.

2.2 Public Interest Effects

The applicant stated that he was prepared to absorb the capital cost of approximately \$90 000 for the wind-powered generator. He submitted that he should in turn receive fair value for the surplus energy delivered to TransAlta. He contended that interconnection of his installation would defer construction of new generating facilities on the Alberta interconnected electric system (AIS), even though only by a small amount compared to the size of the generating units presently being added to the AIS. During periods of surplus energy sales to TransAlta, there would be savings in fuel, operating, and other associated costs to the utilities. Because the wind-powered generator is located close to other distribution loads, transmission and distribution losses would be reduced. Therefore, customers of the AIS would benefit from his installation and, since he has paid the full capital cost for the generator, no one else would be adversely affected.

The applicant stated that, because wind energy is a renewable resource and pollution free, wind-power installations should be encouraged in southern Alberta where there is a high wind regime, particularly in the winter chinook months when the system power demand is also highest. The applicant also expressed the opinion that wind-powered generators should be installed on the basis of their own economic merits, and the price paid for surplus wind energy should not be subsidized by customers of the AIS.

2.3 Sale of Surplus Energy

The applicant stated that, in the first few years, his wind-powered generator would generate more energy annually than his operations required. TransAlta has agreed to interconnect the generator and has offered to purchase any surplus energy generated. TransAlta's offer is based on installing two separate uni-directional meters for the interconnection, one to measure flow to Mr. Sinnott's operation and to be charged at normal utility rates, the other to measure surplus energy flow to TransAlta's system that would be paid for at the price of 1.6¢/kWh, but subject to any further order of the Public Utilities Board. The applicant argued that TransAlta's proposal to purchase surplus energy is unfair because it does not recognize the contribution made by the generator to reduce the need for new capacity on the AIS, and the rate of 1.6¢/kWh offered for his surplus energy is far below its true value.

The applicant proposed two options for the exchange of electricity between him and TransAlta. The first option, which he referred to as "net energy billing", is a sharing of energy and capacity, recognizing the economics to both parties involved. The net excess electric capacity and energy at the end of a billing period would be delivered free of charge to TransAlta who would resell it elsewhere

at full retail value. In return, TransAlta would supply any shortfall in his energy requirements during periods of low or no wind generation. In this arrangement, energy would be measured by allowing the standard meter to run in reverse when surplus energy is being produced. The net energy supplied by TransAlta would be charged at normal utility rates.

The second option suggested was the 'surplus energy purchase' option under which all the energy supplied by TransAlta would be metered and billed at normal utility rates. The energy supplied by the applicant to TransAlta would be metered separately and paid for at a rate equivalent to the highest-cost energy produced on the TransAlta system. This option assumes that the most expensive energy produced by TransAlta (or AIS) would be cut back first during periods when the wind-powered generator is producing excess energy. Determination of highest-cost energy would take into account the displacement fuel and long-term avoided costs associated with that generation. This would require installation of two uni-directional meters wired in series.

2.4 Other Terms and Conditions

The applicant claimed that interconnection and metering costs should be shared between TransAlta and himself, since the wind plant provides some benefits to the customers of TransAlta. Mr. Sinnott was also concerned that the level of third-party insurance that TransAlta insisted he carry is excessive, given the risk associated with the interconnection.

3 INTERVENERS' SUBMISSIONS

D. M. Cousins supported the application. Using Pincher Creek wind data, he calculated a slightly lower average annual output of 112 500 kWh for the wind-powered generator. He stated that at the time of year when the demand on the AIS is at its highest level, the power available from the wind is also at its highest level. Because of the very nature of the wind, the AIS must react very quickly to compensate for fluctuating production from the generators. In his opinion, this reaction would likely be a reduction in water flow to a hydro-generating unit, resulting in storage of that water in the reservoir for use at a later time. Mr. Cousins also stated that the small power producer (SPP) should not be subsidized by the utility or its customers, but sufficient wind-powered generators should be built so that they could be studied and more data gathered about their operation.

R. M. Bennett was in favour of the application. He stated that a higher rate should be paid for sales of any surplus energy and that the net energy billing option should be available to an SPP. Mr. Bennett also argued that TransAlta's requirement for the applicant to carry \$2 million of third-party liability insurance was excessive. He noted

that farm customers who operate standby generators in conjunction with their normal supply from the AIS are not required to carry insurance even though they pose similar risks as the Sinnott installation.

W. Arsene supported the application on the basis that there are employment and economic benefits associated with the wind-energy industry. He favoured a trial period to gain more information regarding wind-powered generator operation and associated costs.

J. Edworthy of Nor'wester Energy Systems Ltd. (Nor'wester Energy) estimated the annual energy production from the wind-powered generator would be about 115 000 kWh. He outlined several benefits of wind power, such as deferment of capital expenditures by the utilities, increased reliability of the system due to generation dispersion, economic benefits, job opportunities, energy diversity, conservation of fossil resources, and protection of the environment. He was of the opinion that the applicant should bear the interconnection and metering costs. He argued that rates set for sale of excess energy to TransAlta should include consideration for avoided line losses (because generation is located near the load), generating capacity credit, avoided fuel costs, and some recognition of the costs of the generation by the SPP. He agreed that the utility and the SPP should not subsidize each other.

Considering that limited information is available on the effects of wind power in Alberta, Mr. Edworthy recommended that the Board adopt an interim policy for the next three years to encourage development of wind power to a maximum total capacity of 100 megawatts. After that time, all relevant issues and policies should be reviewed based on local practical operating experience. He further recommended that, in conjunction with this interim period, a joint committee be established of utility, government, wind-energy industry, and citizen members to monitor wind-powered generator and utility interactions, performance, and concerns raised by the issues discussed at the hearing. This committee would be charged with arriving at recommendations regarding allocation of costs, liability, and other concerns based on operating experience in Alberta and reporting these recommendations to the Board for policy revisions.

Alberta Power Limited (Alberta Power) stated that utility interconnections with customer-owned generation should be encouraged to promote the efficient use of energy resources and the innovative and economic development of conventional and alternative electric energy sources. It argued that all consumers of electricity should benefit from customer-owned generation interconnected with a utility's system. Also, customer-owned generation should be considered as a customer class of negative load with credits for demand (capacity) and energy based on the reduction of system co-incident peak load and savings in

energy generation. Alberta Power suggested that surplus energy from an SPP be bought at a fixed rate which would be somewhat less than what Alberta Power sells its energy for, but one which would make some allowance for capacity credit.

TransAlta supported the principle of customer-owned generation and took the position that any customer may interconnect and operate electrical generation in parallel with TransAlta's system. In order to be fair to the rest of its customers, TransAlta said it is prepared to purchase all of Mr. Sinnott's surplus energy at a price equivalent to avoided AIS energy cost.

TransAlta submitted that it would be more appropriate to use wind data gathered at the Pincher Creek station to compute average annual energy production from Mr. Sinnott's generator, and it estimated this would amount to about 100 000 kWh.

TransAlta noted that the wind-powered generator must be interconnected with an external source of power in order to start and operate it, and that it would shut down if there is a loss of power from the external source. It also noted that the output from the proposed generator is primarily dedicated to supply the applicant's own requirements. Energy would not be available to TransAlta unless it is not required by Mr. Sinnott's own operations. As there is no assurance of supply of any amount to TransAlta at any given time, there could be no capacity costs avoided by TransAlta. Therefore, the value of Mr. Sinnott's surplus energy to TransAlta lies in displacement of AIS energy only, and in a small reduction in transmission losses. In calculating the value of Mr. Sinnott's surplus energy, TransAlta estimated that the generator energy production would be distributed equally over the year, and the net fuel savings would consist of 50 per cent gas and 50 per cent coal. Allowing an additional 5 per cent credit for savings in line losses at the transmission level, TransAlta determined that 1.6¢/kWh would be appropriate for the avoided energy cost. Allowance for savings in line losses at the distribution level should not be included because any potential savings are offset by the need to distribute the surplus energy purchased over the distribution system. TransAlta stated that, if the applicant is prepared to dedicate his capacity to the system, there may well then be some credit for capacity.

TransAlta stated that interconnection and metering costs should be entirely absorbed by the applicant unless the benefits of the wind-powered generator are also shared. TransAlta said it would install, at its own cost, a time-of-day meter on an experimental basis at Mr. Sinnott's facility to assess the capacity the generator can actually provide each hour of the day, and to monitor the characteristics of the generator.

4 BOARD'S VIEWS

This report deals with the specific issues of the application. The applicant also submitted a significant amount of information and related material regarding wind-power production in other jurisdictions. Much of this material is not discussed in this report and may not be applicable to Alberta, but might provide useful information to interested persons.

Since the present application may be the first of many similar applications by SPPs, the Board has dealt specifically with the application in the body of this report and then expanded upon its views, or dealt with other matters, in the appendix. Although each future application would be decided upon its particular merits and facts, some general principles applied by the Board in dealing with this application are discussed in the appendix.

The Board observes that the proposed wind-powered generator is equipped with voltage and frequency protection relays and notes that it meets TransAlta's requirements for parallel operation with the utility system. Furthermore, Mr. Sinnott stated that the generator would comply with standards as set out by the Canadian Standards Association and the Electrical Protection Branch. The safety of linemen working on a line connected to an SPP facility is a valid concern, and the SPP operator must take sufficient precautions. In this respect, the Board is satisfied that Mr. Sinnott and TransAlta will install the necessary equipment required to prevent unsafe occurrences.

A range of estimates of the output of the Sinnott installation was presented and discussed, and the Board believes it would probably be more accurate to use the wind data from the closest meteorological station to the wind-powered generator to compute the annual energy production and the likely economic benefit of the facility to him. In this instance, the differences are small and the overall analysis pertinent to the decision is not materially affected.

On the relationship and effect of Mr. Sinnott's generator on the TransAlta and Alberta systems, as discussed more fully in the appendix, the Board believes that while the effects may be real the impact of a single SPP cannot, at this time, be accurately determined. The relationship and effect of SPPs on the AIS will depend upon the development of SPPs and will require analysis of their operating experience. To this end, the Board believes a concerted effort should be made to obtain credible technical information on the operation and interaction of the generator with TransAlta's system.

The Board does acknowledge some of the potential benefits of SPPs as presented by the Sinnott application. The Board also believes that a desirable environment for the development of SPPs should be encouraged and, in its opinion, a period of experience to gather information

on the performance of SPPs is necessary to reconcile their true impact on the AIS.

The Board notes that the wind-powered generator would be used to meet Mr. Sinnott's own requirement first, and only surplus energy would be made available to TransAlta. Furthermore, Mr. Sinnott needs an interconnection with the distribution system of TransAlta for generator induction power, back-up supply, and to feed surplus energy back to the utility. So in a sense, Mr. Sinnott would continue to be a customer and a load to TransAlta and would be billed at the same rate as other customers with similar loads. To the extent that Mr. Sinnott reduces his own load, the Board believes that this will, on average, reduce TransAlta's generation and tend to delay new generation capacity requirements, even though by a very minute amount. Therefore, TransAlta will see an actual reduction in energy generated since Mr. Sinnott will take less energy from TransAlta than he would have as a pure load, ie with no generator. For these very general and simplistic reasons, the Board believes that, for a trial or learning period, very simple cost procedures should be used for arriving at the value of surplus energy from the applicant's plant. Also, the applicant should then be content to receive some but not all of the perceived, and yet unproven, benefits of his generator.

The Board believes that Mr. Sinnott's operation should be treated as that of a customer who, by managing his load to conserve energy, will reduce his requirements from TransAlta. Furthermore, Mr. Sinnott should be compensated for the surplus energy that he generates by being allowed to "bank" it in TransAlta's system during periods when his generation exceeds his load. Mr. Sinnott would then be able to use his "banked" energy during periods of low or zero generation by drawing energy from the TransAlta system. Although this is similar to the net energy billing concept suggested by the applicant, the Board believes that, during the learning period, two meters should be installed. One meter would record all the energy production from the wind-powered generator and the other would record Mr. Sinnott's consumption, and the difference in the two meter readings would be used to compute the billing. The Board would suggest that the banking and the billing period should be identical and that a quarterly billing period would appear suitable. If during each such period TransAlta is a net supplier of energy to the applicant, then he would be billed for this energy at the usual utility rates, but if the applicant produces more energy than his own requirement during the same period, then TransAlta would compensate him for such surplus energy at a suitable surplus energy rate.

The Board believes there is some definite but unquantifiable capacity contribution made by Mr. Sinnott's wind-powered generator, and that this would be compensated for by the reduction in energy cost to Mr. Sinnott by the

modified net energy billing concept which would allow him to bank excess energy in TransAlta's system for his later use.

The Board believes that any cost to TransAlta of foregoing the charge for the energy Mr. Sinnott produces for himself is a reasonable cost for the trial period with this form of energy production. However, TransAlta should recover the cost of kilowatt demand capacity required by the applicant's operation and provided by TransAlta, just as it would for any other load with a similar service. If the present rate structure does not adequately cover the cost of providing required kilowatt demand capacity, an appeal could be made to the Public Utilities Board to set an appropriate rate.

Respecting the value of surplus energy, TransAlta computed an avoided energy cost derived on the basis of displacement of 50 per cent gas-fired energy and 50 per cent coal-fired energy, plus 5 per cent credit for avoiding line losses at the transmission level. The Board believes that during the trial period this is a fair method for computing costs avoided by TransAlta as a result of net surplus energy delivered to it from the interconnection with the applicant's facilities. The Board believes this interim arrangement would be fair to both parties and would be without substantial subsidy. However, this should be reviewed and adjusted as the cost of service is revised by the Public Utilities Board from time to time.

As stated earlier, the Board believes there should be a trial or learning period to determine the true impact of the Sinnott installation. During this period, TransAlta should, with the co-operation of the applicant, obtain all relevant technical and cost information on the operation and interaction of the Sinnott wind-powered generator with the TransAlta system, and submit to the Board a report on this matter for each calendar year and a final summary report before the end of the trial period. Should the Electric Utility Planning Council choose to submit a report or describe an industry position, the Board would welcome it. This trial or learning period should be for five years ending 31 December 1989.

The Board believes that all costs incurred by TransAlta that are beyond those required to connect and meter a customer of similar service size and class, should be paid for by the applicant. The costs of special test metering during the trial period should be borne by TransAlta, and

the Board was encouraged to hear TransAlta's plans to install a time-of-day meter, at its own cost, for experimental purposes. In addition, all costs incurred by the applicant to allow for the safe and reliable operation of its generation in parallel with TransAlta's system should be borne by the applicant. If further interpretation is required, the Board observes that all parties agreed that neither an SPP nor a utility should subsidize each other.

The Board assumes that TransAlta would treat customers with standby generation, or with a generator such as Mr. Sinnott's, equally; however, the Board considers matters such as liability or insurance to be part of normal business arrangements and should be resolved by negotiation between Mr. Sinnott and TransAlta.

5 DECISION

Having considered the evidence, the Board believes that the construction, operation, and interconnection of the Sinnott wind-powered generating facility is in the public interest and consistent with the requirements of the Hydro and Electric Energy Act.

The Board is prepared to issue a final approval for the operation of the wind-powered generator, and an order to allow the continued inter-connection of the wind-powered generator to the distribution system of TransAlta Utilities Corporation.

DATED at Calgary, Alberta, on 8 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink

F. J. Mink, P.Eng.
Acting Board Member

R. G. Paterson

R. G. Paterson, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives
(Abbreviations used in Report)
Witnesses

A. E. Sinnott

G. Jasman

A. E. Sinnott

D. Gilmer of Enertech Corporation

J. Otis of Wind Dynamics

D. Johnson of Wind Dynamics

TransAlta Utilities Corporation
(TransAlta)

M. H. Patterson, Q.C.

E. J. McCoy

G. D. Lyons, P.Eng.

M. J. Chorel, P.Eng.

Alberta Power Limited
(Alberta Power)

K. F. Miller

C. O. Twa, P.Eng.

B. Laing, P.Eng.

R. V. Baer, P.Eng.

Nor'wester Energy Systems Ltd.
(Nor'wester Energy)

J. Edworthy

J. Edworthy

R. M. Bennett

R. M. Bennett

W. Arsene

W. Arsene

D. M. Cousins, P.Eng.

D. M. Cousins, P.Eng.

Energy Resources Conservation Board staff

M. J. Bruni

A. Kwaczek

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J.N.G. Yu, P.Eng.

S. S. Lota, P.Eng.

APPENDIX

TO DECISION D 84-12 ON THE SINNOT WIND-POWERED GENERATOR

Given the growing interest in small power production and co-generation in Alberta, the Board believes it is appropriate to expand and illustrate its views developed in reaching a decision on the Sinnott application for approval of the operation of a wind-powered generator connected to the Alberta interconnected electric system (AIS). Following this first hearing dealing with the interconnection of a small power production facility and the AIS, the Board concluded that, while the potential benefits and impacts of small power production could be described, the lack of operating experience precluded an adequate assessment of these factors. Considering the interest in the Sinnott application, the Board anticipates this may well be the first of many similar applications.

For purposes of this report, the Board defines a small power producer (SPP) as a connected utility customer that supplies some or all of its own electric load from its own on-site generation of 100 kilowatts or less of total installed name-plate capacity. This is distinct from co-generation, which usually involves the generation of electricity with thermal energy required for some other purpose. Such co-generation is often associated with large industrial projects and is negotiated as part of a supply contract with the appropriate electric utility. Furthermore, most co-generation projects to date have involved generating capacities much larger than those associated with SPPs.

Benefits to Alberta

The Board recognizes that favourable wind regimes occur in much of Alberta, creating considerable potential for development of wind-powered electric generation. The development of wind-powered electric generation, and the possibility of other forms of small power production which would utilize renewable resources, would be desirable even at a modest scale as environmentally sound energy sources that would conserve non-renewable resources. The economics largely remain to be tested and proven. The development of small power production facilities could conceivably provide a unique opportunity for modest economic benefits to Alberta's agricultural industry as well as job opportunities in the design, manufacture, and installation of such facilities. It is apparent that the technology in this area has made considerable progress in recent years. The Board accepts that the technology exists to make the small power production both safe and compatible with the AIS.

In light of the potential benefits, and considering the need for information on the operation of SPP facilities appropriate to the Alberta energy scene, the Board believes that a suitable environment for development of small power production facilities is advisable for a trial period.

Interaction of SPP Facilities and Utility Systems

In considering the suitability of SPP facility development, it is necessary to consider their interaction with a large electric utility system and the AIS. The Board observes that major impacts such as the addition of a power plant, a large industrial consumer, or even an industrial co-generator can be measured and predicted with some degree of accuracy. When it comes to an SPP, the effects are small and measured in minute increments of utility operations. The Board concludes that although the effect may indeed be real, the arguments as to their nature tend to be hypothetical simply because any measure of an impact is lost in the myriad of other small loads on the system. The major issue surrounding the development of small power production usually revolves around the benefits such facilities provide to the AIS, and accordingly, what the price of surplus energy delivered to the AIS should be. The Board believes that one approach to resolving this problem exists in the statistical methods used by the utilities to plan for the numerous small loads scattered throughout the system. While no individual small load causes a utility to add a generator, the cumulative growth can be estimated within certain confidence limits, and it is this aggregate of small loads which ultimately creates the need for additional generators. The degree of confidence depends on both the large number of small loads and the utilities' experience in planning for and servicing small loads.

Similar experience does not exist for SPPs, however, the Board believes the methodology would be appropriate and should be more useful than the essentially hypothetical arguments. Although these arguments cannot be discarded entirely, only operating experience with SPP facilities will provide any resolution. A concerted effort should therefore be made to obtain valid information on the operation and interaction of SPPs with the AIS. The Board believes that the installation and operation of special instrumentation for such purposes, ie other than standard meters for billing, should be the responsibility of the utility. This detailed information on the performance of an SPP facility is fundamental to determining the relationship to the utility in respect to peaking coincidence, capacity, and potential for some degree of dedication of capacity. The utilities have the expertise for such an evaluation at the common interface with SPPs and are also able to observe the overall impact of SPPs on the system.

Economic Considerations

For any individual SPP to provide the quality of service available from a utility would require several generators, spinning reserve, and perhaps even energy storage at the SPP facility site. It is very unlikely that this would be cost competitive with large-scale utility generation.

In fact, economic analysis similar to that which a utility would use to evaluate a new generating source would indicate that small power production facilities are probably not as economic as utility service. However, the SPP utilizing a renewable resource to supply part or all of its own load, and generating some surplus for sale to a utility, may be in a better position from its own viewpoint. In the case of a farm operator, there is apparently the satisfaction of self-sufficiency and the knowledge of predetermined electric energy costs. In some cases, the SPP might have tax advantages that would make the installation economically attractive to the operator even though unattractive under utility financing.

While the Board is concerned about conservation of any energy resource, it cannot ignore economic and efficient recovery of it anymore than it can ignore economic and orderly development of the AIS. At the hearing of the Sinnott application there was a consensus that neither SPPs nor the utilities and their customers should subsidize one another. In developments to date, initiative has been shown by the few SPPs and there has been co-operation by the utilities to conserve the energy produced.

Interim Policy

As noted before, the Board does not believe it is possible at this time to calculate in great detail the effects, and hence the costs and benefits, of an SPP facility. Instead, the following is presented as a basis for a suitable compromise between the interests of the SPP and utilities for an interim trial and learning period.

The Board expects that small SPPs will request interconnection with the utility for technical reasons, back-up supply, and to feed surplus energy back to the utility. So in a real sense the SPP continues to be a customer and a load to the utility, and the net energy in kilowatt hours (kWh) and the peak load demand in kilowatts supplied by the utility would be billed at a similar rate as for other customers with similar loads.

To the extent that the SPP reduces its own load on an annual and peak time basis, it will on average reduce utility generation and tend to delay new generators, thereby reducing AIS cost. Conversely, if it takes little net energy but continues to take full power demand at time of system peak, it will not delay additional generation and, again on average, could tend to reduce the AIS load factor and thereby slightly increase generating costs.

Turning to energy fed back into the AIS and theoretically distributed to nearby utility customers, the Board expects that the only effect on the utility will be a nearly negligible reduction in the actual on-line AIS generation.¹

¹ The Board recognizes that the effect is real but is probably so small as to be lost among all the other loads continually varying on the system.

Whatever-surplus energy the SPP produces would be absorbed by other customers of the utility at that moment and paid for by them at a fixed rate, and for its customers other than the SPP the utility sees no change. The utility will continue to recover its revenue from all other customers as though there were no effect from the SPP. The only "change" seen by the utility, if it is really a change, is that the SPP has on average taken less kWh from the system than it would have as a pure load. Admittedly, the utilities would have some increased administrative costs due to SPPs.

For these very general and admittedly simplistic reasons, the Board believes that very simple cost-recovery procedures should be applied during a trial or learning period during which the impact of SPPs should be studied. During this trial period, the Board expects there will be few SPPs and their effect on the AIS will be minimal. If the simple cost procedures as proposed are in error, then in the interim the error should probably be absorbed by the much larger utilities and the many customers of the AIS in the interest of conservation. The SPPs should in turn be content to receive some but not all of the perceived but not proven benefits of their pioneering.

The simple procedures that the Board believes should be applied during the trial period would regard an SPP as a load on the AIS. As with any customer load that is managed by the customer to conserve energy, that load will probably be less than it would have been without such management. Application of what has been termed "net energy billing", in which one meter records supply to an SPP and another the energy flowing to the system from the SPP should present no great hardship to the utility but would provide a substantial advantage to the SPP that is able to "bank" its energy with the utility and withdraw it as needed.

Very simply, for the trial period, an SPP should be allowed to displace utility generation, and to recover that energy from utility generation at some other time. The Board recognizes that hydroelectric power plants can store energy but it is not convinced that SPP energy would actually be stored. Therefore, for the present, it regards the energy exchange under net energy billing as more in the nature of a banking arrangement that the utility provides as a service to the SPP. If during a normal billing period (probably quarterly) the SPP consumes more energy than it produces, then the SPP would be billed at the usual rates for net energy supplied. If the SPP produces more energy during a normal billing period than its own requirements, then the utility should compensate the SPP for excess energy at the true value of the energy to the utility and its other customers. Normally this value will be the utility's avoided cost and will be less than the rate charged for net energy supplied to the SPP.

In determining the true value of such surplus energy, the Board believes there could well be some capacity contribution by an SPP but the value of any such capacity cannot be determined at this time. However, the Board believes any capacity contribution would almost certainly be more than compensated by the reduction in energy cost to the SPP under net energy billing. The Board believes that any cost to the utility of foregoing the energy charge for kWh the SPP produces for itself would be minimal, but in any case is a reasonable cost during the experimental period for this form of energy conservation. The utility in turn should recover through demand charges and connection contribution its true cost of capacity that the SPP load imposes, just as it would for any other with a similar service. This may be covered by the fixed charges for service or, in some cases, by some form of demand metering; but the Board believes it should be a true utility capacity cost and should not diminish the value of SPP-generated electricity. If the utilities are convinced the present rate structure does not adequately cover cost of capacity in such circumstances, the Public Utilities Board should be asked to determine an appropriate rate.

As stated previously, there are some benefits to the AIS of SPP-installed capacity that are not quantifiable at this time but would be compensated by net energy billing. The Board believes that TransAlta's suggested avoided fuel cost calculated on the basis of 50 per cent gas-fired energy and 50 per cent coal-fired energy is a suitable compromise as compared to the most expensive avoided fuel on the AIS. Savings in line losses at the transmission as well as the distribution level may exceed 5 per cent, but 5 per cent is appropriate during the trial period. The Board believes that it would be fair to SPPs in the interim and also without substantial subsidy by the utilities and their customers. Furthermore, this rate should be reviewed and adjusted as the cost of service is adjusted by the Public Utilities Board from time to time. The Board makes this recommendation without prejudice to the true impact of SPPs that may be determined over the trial period. The Board also notes that an SPP must recognize that further study may show that the value of an SPP to the AIS using this approach is overrated and lower credits might be implemented after the trial period. Correspondingly, if the benefits are clearly demonstrated to be higher, the credits to the SPP for surplus energy may be increased.

Trial Period

As noted before, and until more complete information is available, the Board believes this simple procedure favours the SPP that improves energy conservation by reducing load on the AIS or by generating surplus energy. The utilities may be carrying some small cost over the experimental period and both the period and the number of SPPs should be modestly restricted. The Board believes the experimental period, during which the utilities should

ensure that adequate information is obtained and discussed with SPPs and the Board, should be for about five years until 31 December 1989. Such a period would allow for several other SPPs to be connected to the AIS after the Sinnott machine is in service, and still allow several years for evaluation of such SPPs. Should the number of SPPs increase much more rapidly than presently expected, the experimental period should end sooner and the whole question of equitable cost and the economics of conservation should be reviewed.

The Board recommends that, if and when the number of SPPs on the AIS reaches 150 or the total connected SPP generation equals 10 000 kilowatts, the experimental period should end and a report of their impact should be rendered. Furthermore, the Board believes the total SPP generating capacity connected to any one distribution feeder should not exceed half the utility substation supply capacity to that distribution feeder unless the utility operator can satisfy the Board that some other amount is more appropriate.

During the experimental period each utility, assisted by SPPs on its system, should obtain technical and cost information on the operation and interaction of SPPs with the AIS and submit to the Board an annual report by 31 March on the operations to the end of the previous year, and a final summary report by 31 July 1989.

Interconnection Costs

The Board believes that all interconnection costs incurred by the utility beyond those required to connect a customer of similar service, size, and class should be paid by the SPP. Costs of special test metering during the trial period should be borne by the utility. In addition, all costs incurred by the SPP to allow the safe and reliable operation of its generation as part of the AIS should be borne by the SPP. The basic premise on costs should be that all parties agreed that neither the SPP nor the utilities should subsidize one another. Matters relating to liability and insurance were raised at the hearing. The Board believes these matters relate to a normal business transaction between the SPP and the utility and should be resolved between the parties, but suggests that the utilities take into account their treatment of existing customers who have installed standby generation. The Board recognizes and accepts that all parties are entitled to and must protect their own interests, but would hope this can be accomplished without resorting to a purely legalistic approach.

SUMMARY

The Board found that some of the issues raised to date may be relevant but their impact is indeterminable at this time. However, three points did stand out from all the discussion and argument about the impacts and relationships of a small power producer and an electric utility.

- A small power producer generating wind-powered energy cannot fully utilize and conserve such energy for its own purposes without some means of matching the availability of that energy to the small power producer's own load. Such means of matching are not available at reasonable cost independent of the larger interconnected electric system.
- An electric utility is a customer-oriented regulated enterprise that provides needed electric service at the lowest reasonable cost. Over the years to date, electric utilities have been innovative in meeting the needs of their customers through new types of services and the development of new forms of contracts that recognized the true cost of providing service.
- The parties agreed that they should not subsidize one another, and that each should be able to pursue its business without acquiring costs or benefits of the other party. There appeared to be no quarrel with charging or paying for actual costs or benefits — what disagreement there was arose from different understandings and perceptions of impacts, costs, and benefits.

The Board concludes the available evidence at this time does not provide an answer as to the true impact of SPPs on the AIS. The Board does not consider it proper to impose a compromise somewhere between the opposing perceptions of reality. What should be provided is the service the customers need, and the Board sees this as a banking service by utilities for wind-generated electricity and not as storage on the interconnected electric system. Naturally, there is a cost to providing such a service and the true cost remains to be determined. In the interim, a simple means of implementing the service on a trial basis for five years has been put forward. The banking service will probably not result in a perfect matching of customer generated energy with customer load, and any net energy supplied by the utility should be charged at normal utility rates and any net surplus energy generated and delivered to the utility should be at the avoided energy cost actually realized by the utility. The basis for determining the latter is proposed to be at 50 per cent gas-fired energy and 50 per cent coal-fired energy, plus about 5 per cent credit for avoiding line losses. Actual rates should be determined by the Public Utilities Board and adjusted as required.